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Transcript Exhibit(s)

Docket #(s): E-04204A-06-0783

Exhibit # : S2-29, S32-38, S40-46, S48-56, S58, S60-68, UNSE 1-59, RUCO 1-10, RUCO 13-15, MAGRUDER 1-6, 8, 9, 11-15, 17, 18, 20-25, 27, 28.

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One South Church Avenue
Tucson, Arizona 85701

April 2, 2007

James S. Pignatelli
Chairman of the Board

(520) 571-4000

Dear Shareholders:

You are cordially invited to attend the UniSource Energy Corporation 2007 Annual Shareholders' Meeting (the "Meeting") to be held on Friday, May 11, 2007, at the FOX Theatre, 17 West Congress, Tucson, Arizona. The Meeting will begin promptly at 10:00 a.m., Mountain Standard Time, so please plan to arrive earlier. No admission tickets will be required for attendance at the Meeting. We have included a map indicating the location of the FOX Theatre and parking options in the downtown area near the Theatre.

Directors and officers will be available before and after the Meeting to speak with you. During the Meeting, we will answer your questions regarding our business affairs and we will consider the matters explained in the enclosed Proxy Statement.

We have enclosed a proxy card that lists all matters that require your vote. Please complete, sign, date and mail the proxy card as soon as possible, whether or not you plan to attend the Meeting. You may also vote by telephone or the Internet, as explained on the enclosed proxy card. If you attend the Meeting and wish to vote your shares personally, you may revoke your proxy at that time.

Your interest in and continued support of UniSource Energy Corporation are much appreciated.

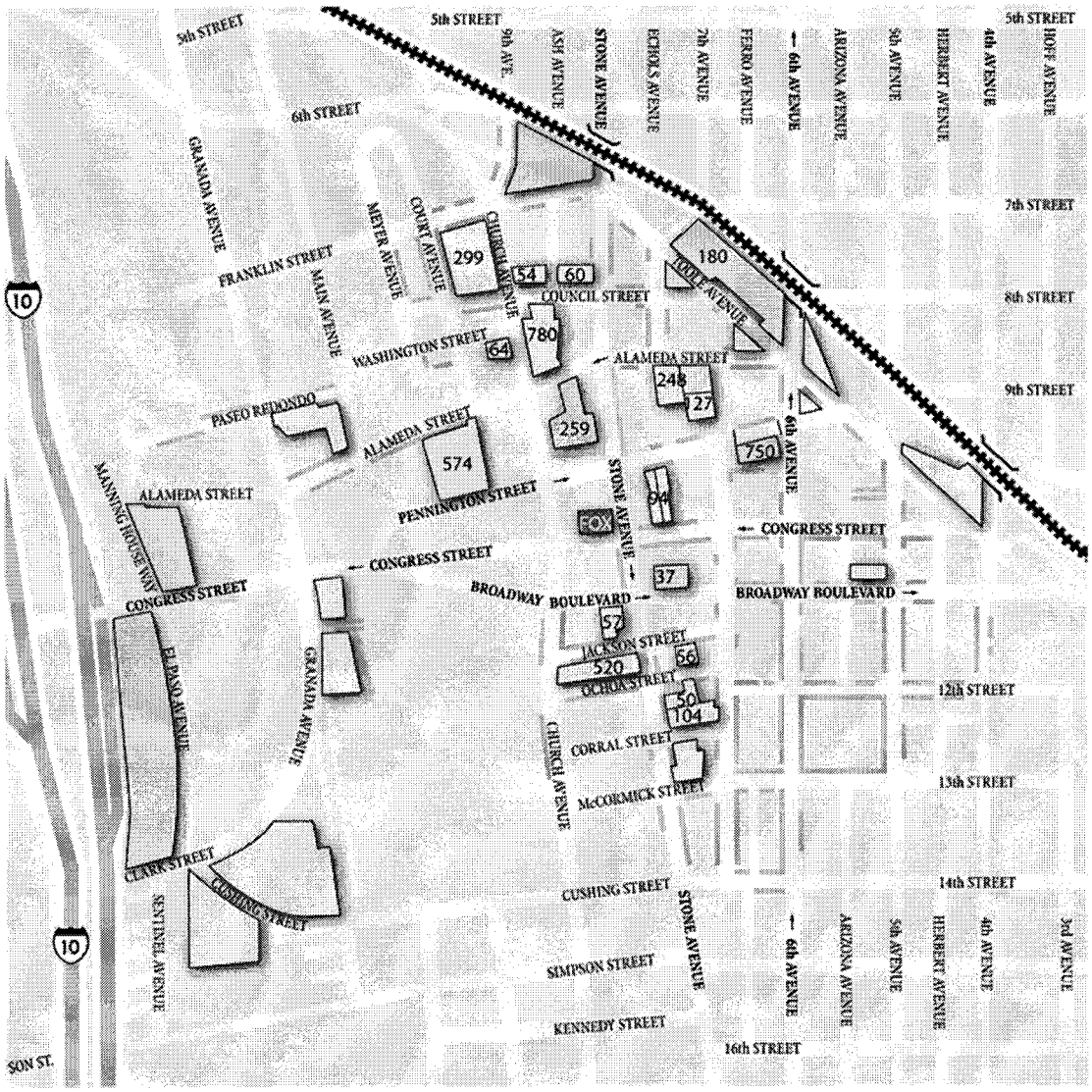
Sincerely,

UNISOURCE ENERGY CORPORATION

James S. Pignatelli
Chairman of the Board, President and
Chief Executive Officer

Downtown Tucson Public Parking

TUCSON THEATRE
17 WEST CONGRESS



Parking within a 3 block radius of the Fox

Parking Garages and Surface Lots	4,723 spaces
Street Parking and meters (not shown)	353 spaces
TOTAL	**5,076 spaces**

Notice: *Please confirm with Garage or Lot for hours of operation and applicable parking fees. This map is for informational purposes only. The Fox Tucson Theatre and its employees can not guarantee parking availability in the garages or lots listed on the parking map as the Fox Tucson Theatre does not have dedicated parking facilities. The Fox Tucson Theatre and its employees are not responsible for cars left in garages/lots past hours of operation.*

NOTICE OF ANNUAL SHAREHOLDERS' MEETING

To the Holders of Common Stock of
UniSource Energy Corporation

We will hold the 2007 Annual Shareholders' Meeting of UniSource Energy Corporation at the FOX Theatre, 17 West Congress, Tucson, Arizona, on Friday, May 11, 2007, at 10:00 a.m., Mountain Standard Time ("MST"). The purpose of the Meeting is to:

1. elect 12 directors to our Board of Directors for the ensuing year;
2. ratify the selection of the independent auditor for 2007; and
3. consider any other matters which properly come before the Meeting.

Only shareholders of record at the close of business on March 26, 2007, are entitled to vote at the Meeting.

We have enclosed our 2006 Annual Report, including audited financial statements, and the Proxy Statement with this notice. Proxy soliciting material is first being sent or given to shareholders on or about April 2, 2007. Your proxy is being solicited by our Board of Directors.

Please complete, sign, date and mail the enclosed proxy card as soon as possible, or vote by telephone or the Internet, as explained on the enclosed proxy card.

Linda H. Kennedy
Corporate Secretary

Dated: April 2, 2007

YOUR VOTE IS IMPORTANT

EACH SHAREHOLDER IS URGED TO COMPLETE, SIGN, DATE AND RETURN PROMPTLY THE ENCLOSED PROXY CARD BY MAIL, OR TO VOTE BY TELEPHONE OR THE INTERNET, AS EXPLAINED ON THE ENCLOSED PROXY CARD. IF THE MAIL OPTION IS SELECTED, USE THE ENCLOSED ENVELOPE, WHICH DOES NOT REQUIRE POSTAGE IF MAILED IN THE UNITED STATES. RETURNING A SIGNED PROXY WILL NOT PROHIBIT YOU FROM ATTENDING THE MEETING AND VOTING IN PERSON IF YOU SO DESIRE.

UNISOURCE ENERGY CORPORATION
One South Church Avenue
Tucson, Arizona 85701

ANNUAL SHAREHOLDERS' MEETING
PROXY STATEMENT

ANNUAL MEETING:

May 11, 2007	FOX Theatre
10:00 a.m., MST	17 West Congress
	Tucson, AZ 85701

RECORD DATE:

The record date is March 26, 2007 ("Record Date"). If you were a shareholder of record at the close of business on the Record Date, you may vote at the 2007 Annual Shareholders' Meeting ("Meeting") of UniSource Energy Corporation ("UniSource Energy" as well as references to the "Company," "we," "our" and "us"). At the close of business on the Record Date, we had 35,272,970 shares of common stock outstanding.

AGENDA:

1. Proposal One: Elect 12 directors to our Board of Directors ("Board") for the ensuing year.
2. Proposal Two: Ratify the selection of the independent auditor for 2007.
3. Proposal Three: Consider any other matters which properly come before the Meeting and any adjournments.

INDEPENDENT AUDITOR:

Representatives of PricewaterhouseCoopers, LLP are expected to be present at the Meeting with the opportunity to make a statement and respond to appropriate questions from our shareholders.

PROXIES:

A form of proxy for execution by shareholders is enclosed. Unless you tell us on the proxy card to vote differently, we will vote signed returned proxies "for" the Board's nominees. The Board or proxy holders will use their discretion on other matters that properly come before the Meeting. If a nominee cannot or will not serve as a director, the Board or the persons designated as proxies will vote for a person whom they believe will carry on our present policies.

PROXIES SOLICITED BY:

The Board.

FIRST MAILING DATE:

We anticipate first mailing this Proxy Statement along with the proxy card on or about April 2, 2007.

REVOKING YOUR PROXY:

You may revoke your proxy before it is voted at the Meeting. To revoke, follow the procedures listed on page 3 under "Voting Procedures/Revoking Your Proxy."

COMMENTS:

Your comments about any aspects of our business are welcome. You may use the space provided on the proxy card for this purpose, if desired. Although we may not respond on an individual basis, your comments help us to measure your satisfaction, and we may benefit from your suggestions.

PLEASE VOTE – YOUR VOTE IS IMPORTANT

Prompt return of your proxy will help reduce the costs of re-solicitation.

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* We expect to vote on this item at the Meeting.

VOTING PROCEDURES/REVOKING YOUR PROXY

You can vote by telephone, the Internet, mail or in person.

You can vote your shares by telephone, the Internet, mail or in person at the Meeting. Your proxy card contains instructions for voting by telephone or the Internet, which are the least expensive and fastest methods of voting. To vote by mail, complete, sign and date your proxy card, or your broker's voting instruction card if your shares are held by your broker, and return it in the enclosed return envelope.

Under Arizona law, a majority of the shares entitled to vote on any single matter which may be brought before the Meeting will constitute a quorum. Business may be conducted once a quorum is represented at the Meeting. Except as otherwise specified by law or in our Articles of Incorporation or Bylaws, if a quorum exists, action on a matter other than the election of directors will be deemed approved if the votes cast in favor of the matter exceed votes cast against it.

Directors are elected by a plurality of votes.

Directors are elected by a plurality of the votes cast by the shares entitled to vote if a quorum is present. A plurality means receiving the largest number of votes, regardless of whether that is a majority. Withheld votes will be counted as being represented at the Meeting for quorum purposes but will not have an effect on the vote.

You may cumulate your votes for directors.

In the election of directors, each shareholder has the right to cumulate his votes by casting a total number of votes equal to the number of his shares of common stock multiplied by the number of directors to be elected. He may cast all of such votes for one nominee or distribute such votes among two or more nominees. For any other matter that may properly come before the Meeting, each share of common stock will be entitled to one vote.

You can revoke your proxy after sending it in by following these procedures.

Any shareholder giving a proxy has a right to revoke that proxy by giving notice to UniSource Energy in writing directed to the Corporate Secretary, UniSource Energy Corporation, One South Church Avenue, Suite 1820, Tucson, Arizona 85701, or in person at the Meeting at any time before the proxy is exercised. Those who fail to return a proxy or fail to attend the Meeting will not count towards determining any required plurality, majority or quorum.

The shares represented by an executed proxy will be voted for the election of directors or withheld in accordance with the specifications in the proxy. If no specification is made in an executed proxy, the proxy will be voted in favor of the nominees as set forth herein.

Proxy Solicitation

We will bear the entire cost of the solicitation of proxies. Solicitations will be made primarily by mail. In addition, we may make additional solicitation of brokers, banks, nominees and institutional investors pursuant to a special engagement of DF King & Co., Inc., at a cost of approximately $10,500 plus reasonable out-of-pocket expenses. Solicitations may also be made by telephone, facsimile or personal interview, if necessary, to obtain reasonable representation of shareholders at the Meeting. Our employees may solicit proxies but they will not receive additional compensation for such services. We will request brokers or other persons holding shares in their names, or in the names of their nominees, to forward proxy materials to the beneficial owners of such shares or request authority for the execution of the proxies. We will reimburse brokers and other persons for reasonable expenses they incur in sending these proxy materials to you if you are a beneficial holder of our shares.

UNISOURCE ENERGY SHARE OWNERSHI P

Security Ownership of Management

The following table sets forth the number and percentage of shares of UniSource Energy common stock beneficially owned as of March 1, 2007 and the nature of such ownership by each of our directors (all of whom are nominees), our Chief Executive Officer ("CEO") and our four other most highly compensated executive officers (together with our CEO, the "Named Executives") for the year ended December 31, 2006, and all directors and officers as a group. Ownership includes direct and indirect (beneficial) ownership, as defined by the SEC rules.

Name and Title of Beneficial Owner	Amount and Nature of Beneficial Ownership[1]					Other[2]		
	Directly Owned Shares	Shares Purchased Under the 401(k) Plan	Shares Subject to Options Exercisable Within 60 Days	Total Beneficial Ownership	Percent of Class	Restricted Stock Units	Deferred Shares Under Deferred Compensation Plan	Total
James S. Pignatelli Chairman, President and Chief Executive Officer	36,067	18,416	685,772	740,255	2.1%	117,271	30,854	888,380
Lawrence J. Aldrich Director	3,912	0	8,358	12,270	*	4,031	0	16,301
Barbara M. Baumann Director	0	0	0	0	*	2,520	0	2,520
Larry W. Bickle Director	6,652	0	11,558	18,210	*	3,153	0	21,363
Elizabeth T. Bilby Director	705	0	11,558	12,263	*	4,462	3,607	20,332
Harold W. Burlingame Director	2,905	0	11,558	14,463	*	5,182	0	19,645
John L. Carter Director	13,459	0	11,558	25,017	*	3,795	10,708	39,520
Robert A. Elliott Director	1,813	0	1,196	3,009	*	2,995	0	6,004
Daniel W. L. Fessler Director	2,260	0	2,358	4,618	*	3,089	0	7,707
Kenneth Handy Director	1,405	0	6,358	7,763	*	5,314	1,576	14,653
Warren Y. Jobe Director	1,313	0	6,358	7,671	*	4,833	0	12,504
Joaquin Ruiz Director	0	0	0	0	*	2,520	0	2,520
Raymond S. Heyman Senior Vice President and General Counsel	29	965	16,667	17,661	*	0	82	17,743
Dennis R. Nelson Senior Vice President, Utility Services	0	8,850	0	8,850	*	26,065	2,348	37,263
Kevin P. Larson Senior Vice President, Chief Financial Officer and Treasurer	28,435	2,456	90,483	121,374	*	0	1,018	122,392

Michael J. DeConcini Senior Vice President and Chief Operating Officer, Transmission and Distribution	8,941	5,161	131,037	145,139	*	25,752	678	171,569
All directors and executive officers as a group	197,716	42,368	1,093,742	1,333,826	3.8%	226,912	55,013	1,615,751

*Represents less than 1% of the outstanding common stock of UniSource Energy.

(1) Amounts include the following:

- Any shares held in the name of the spouse, minor children or other relatives sharing the home of the director or officer. Except as otherwise indicated below, the directors and officers have sole voting and investment power over the shares shown. Voting power includes the power to direct the voting of the shares held, and investment power includes the power to direct the disposition of the shares held.
- Shares subject to options exercisable within 60 days, based on information from E*Trade, UniSource Energy's stock option plan administrator.
- Equivalent share amounts allocated to the individuals' 401(k) Plan which, since June 1, 1998, has included a UniSource Energy Stock Fund investment option.

(2) While amounts in the "Other" column do not represent a right of the holder to receive stock within 60 days, these amounts are being disclosed because management believes they reflect similar objectives of 1) encouraging directors and officers to have a stake in the Company, and 2) aligning interests of directors and officers with those of shareholders.

Security Ownership of Certain Beneficial Owners

As of March 1, 2007, based on information reported in filings made by the following persons with the SEC or information otherwise known to us, the following persons were known or reasonably believed to be, as more fully described below, the beneficial owners of more than 5% of our common stock:

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common	First Trust Portfolios L.P. 1001 Warrenville Road Lisle, IL 60532	2,647,517 (1)	7.5%
Common	Prospector Partners, L.L.C. 370 Church Street Guilford, CT 06437	2,465,668 (2)	6.8%
Common	T. Rowe Price Associates, Inc. 100 E. Pratt Street Baltimore, MD 21202	2,428,517 (3)	6.8%
Common	Barclays Global Investors, NA 45 Fremont Street San Francisco, CA 94105	2,046,489 (4)	5.8%

(1) In a statement (Schedule 13G) filed with the SEC on January 26, 2007, First Trust Portfolios L.P indicated it has shared voting and shared dispositive power over 2,647,517 shares of our common stock.

(2) In a statement (Schedule 13G) filed with the SEC on February 13, 2007, Prospector Partners, L.L.C. ("Prospector Partners") indicated it has sole voting and sole dispositive power over 1,474,497 shares, and shared

voting and shared dispositive power over 991,170 shares of our common stock. Prospector Partners shares investment discretion over the shares with White Mountains Advisors LLC ("White Mountains"), pursuant to a sub-advisory agreement between Prospector Partners and White Mountains.

(3) In a statement (Schedule 13G) filed with the SEC on February 14, 2007, T. Rowe Price Associates, Inc. ("Price Associates") indicated it has sole voting power over 315,400 shares and sole dispositive power over 2,428,517 shares of our common stock. These securities are owned by various individual and institutional investors which Price Associates serves as investment adviser with power to direct investments and/or sole power to vote the securities. For purposes of the reporting requirements of the Securities Exchange Act of 1934, as amended, Price Associates is deemed to be a beneficial owner of such securities; however, Price Associates expressly disclaims that it is, in fact, the beneficial owner of such securities.

(4) In a statement (Schedule 13G) filed with the SEC on January 23, 2007, Barclays Global Investors, NA indicated that it has sole voting power over 1,890,165 shares of our common stock and sole dispositive power over 2,046,489 shares of our common stock. The filing indicated that the 2,046,489 shares are owned by Barclays Global Investors, NA (883,734 shares), Barclays Global Fund Advisors (1,140,329 shares), and Barclays Global Investors, LTD (22,426 shares).

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, and regulations of the SEC require our executive officers, directors and persons who beneficially own more than 10% of our common stock, as well as certain affiliates of those persons, to file initial reports of ownership and transaction reports covering any changes in ownership with the SEC and the New York Stock Exchange ("NYSE"). SEC regulations require these persons to furnish us with copies of all reports they file pursuant to Section 16(a).

Based solely upon a review of the copies of the reports received by us and on written representations of our directors and officers, we believe that during fiscal year 2006, except as described below, all filing requirements applicable to executive officers and directors were complied with in a timely manner. Form 4s were filed late during 2006 for the following referenced persons on the indicated dates reporting certain acquisitions and dividend equivalents credited under the UniSource Energy Corporation Management and Directors Deferred Compensation Plan: for each of Mr. DeConcini, Mr. Larson and Ms. Kissinger, on March 1, April 13 and October 30; for each of Mr. Nelson and Mr. Hansen, on April 13; for Mr. Handy, on January 11, March 1, April 7, April 13, October 24 and October 30; for Mr. Burlingame, on January 11; for Mr. Bickle, on March 1 and April 7; for Ms. Bilby, on April 13, October 24 and October 30; for Mr. Carter, on January 11 and April 13.

PROPOSAL ONE: ELECTION OF DIRECTORS

General Information

At the Meeting, our shareholders of record will elect 12 directors to serve on our Board for the ensuing year and until their successors are elected and qualified. The shares represented by executed proxies in the form enclosed, unless withheld, will be voted for the 12 nominees listed below, or, in the discretion of the persons acting as proxies, will be voted cumulatively for one or more of such nominees. All of the current nominees are present members of the Board. All of the nominees have consented to serve if elected. If any nominee becomes unavailable to serve for any reason, or a vacancy should occur before the election, it is the intention of the persons designated as proxies to vote, in their discretion, for other nominees.

BOARD NOMINEES

James S. Pignatelli

Chairman of the Board, President and Chief Executive Officer of UniSource Energy since July 1998; Chairman of the Board of Directors, President and Chief Executive Officer of Tucson Electric Power Company ("TEP"), the principal subsidiary of UniSource Energy, since July 1998; Chairman of the Board of Directors, President and Chief Executive Officer of Millennium Energy Holdings, Inc. ("Millennium"), a wholly owned subsidiary of UniSource Energy, since 1997; Director of UniSource Energy Services, Inc. ("UES"), a wholly owned subsidiary of UniSource Energy, since 2003. Board member since 1998. Age 63.

Lawrence J. Aldrich (4)(5)

President of Aldrich Capital Company since January 2007; Chief Operating Officer of The Critical Path Institute from January 2006 to December 2006; General Partner of Valley Ventures, LP from September 2002 to December 2005; Managing Director and Founder of Tucson Ventures, LLC, from February 2000 to September 2002; Director of TEP and Millennium since 2000; Director of UES since 2004. Board member since 2000. Age 54.

Barbara M. Baumann (1)(2)(4)

President and Owner of Cross Creek Energy Corporation since 2003; Executive Vice President of Associated Energy Managers, LLC from 2000 to 2003; Director of St. Mary Land & Exploration since 2002; Director of TEP since 2005. Board member since 2005. Age 51.

Larry W. Bickle (4)(5)

Director of St. Mary Land & Exploration since 1995; Executive in Residence for Haddington Ventures, LLC, an investment company ("Haddington"), since January 2006; Managing Director of Haddington from 1997 to 2005; Director of Millennium since 1998; Director of UES since 2004. Board member since 1998. Age 61.

Elizabeth T. Bilby (4)(5)

Retired President of Gourmet Products, Inc., an agricultural product marketing company; retired Director of Marketing of Green Valley Pecans; Director of TEP since 1995; Director of Millennium since 1998; Director of UES since 2004. Board member since 1995. Age 67.

Harold W. Burlingame (1)(2)(3)

Former Executive Vice President of AT&T; Chairman of ORC Worldwide since December 2004; Director of TEP since 1998. Board member since 1998. Age 66.

John L. Carter (1)(2)(3)(4)

Retired as Executive Vice President and Chief Financial Officer of Burr Brown Corporation in 1996; Director of TEP since 1996; Director of Millennium since 1998; Director of UES since 2004; UniSource Energy Lead Director since 2005.Bo ard member since 1996. Age 72.

Robert A. Elliott (1)(3)(5)

President and owner of The Elliott Accounting Group since 1983; Director and Corporate Secretary of Southern Arizona Community Bank since 1998; Television Analyst/Pre-game Show Co-host for Fox Sports Arizona since 1999; Chairman of the Board of Tucson Metropolitan Chamber of Commerce from 2002 to 2003; Treasurer of Tucson Urban League from 2002 to 2003; Chairman of the Board of Tucson Urban League from 2003 to 2004; Chairman of the Board of the Tucson Airport Authority from January 2006 to January 2007; Director of TEP since May 2003. Board member since 2003. Age 51.

Daniel W. L. Fessler (2)(3)(5)

Professor Emeritus of the University of California; Partner in the law firm of LeBoeuf, Lamb, Greene & MacRae LLP from 1997 to 2003; previously served on the UniSource Energy and TEP boards of directors from 1998 to 2003; Managing Principal of Clear Energy Solutions, LLC since December 2004; Director of TEP since 2005. Board member since 2005. Age 65.

Kenneth Handy (1)(3)(4)

Retired Certified Public Accountant; former financial executive with Kaiser Permanente Medical Care Program, Oakland, California; Director of Millennium from 2001 to 2003; Director of TEP since 2001. Board member since 2001. Age 68.

Warren Y. Jobe (1)(2)(4)

Certified Public Accountant (licensed, but not practicing); Senior Vice President of Southern Company from 1998 to 2001; Director of WellPoint Health Networks, Inc. from 2001 to December 2004; Director of WellPoint, Inc. since December 2004; Director of HomeBanc Corporation since 2004; Trustee of STI Classic Funds since 2004; Director of TEP since 2001; Director of Millennium from 2001 to 2003. Board member since 2001. Age 66.

Joaquin Ruiz (1)(2)(5)

Professor of Geosciences, University of Arizona since 1983; Associate Editor, "Geology," Geological Society of America from 2000 to 2002; Dean, College of Science, University of Arizona since 2000; Chair, Search Committee for the Dean of College of Education, University of Arizona from 2002 to 2003; Member of Board of Natural Resources of the National Research Council from 2002 to 2005; Member, Human Resources Committee, American Geological Institute from 2000 to 2005; Member, Governing Board, Instituto Nacional de Astronomia, Optica y Electronica, Mexico since 2003; Board Member, Center to Improve Diversity in Earth Systems Sciences, Inc. since 2003; Member of Board of Earth Sciences, National Research Council of the National Academy of Sciences since 2005; Associate Editor, "American Journal of Science" since 2005; Associate Editor, American Presidents Advisory Board of Research Corporation since 2005; TEP Board Member since 2005; UES Board member since 2005. Board Member since 2005. Age 55.

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(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Corporate Governance and Nominating Committee.
(4) Member of the Finance Committee.
(5) Member of the Environmental, Safety and Security Committee.

The Board recommends that you vote "FOR" these nominees.

PROPOSAL TWO: RATIFICATION OF SELECTION OF INDEPENDENT AUDITOR

The Audit Committee has selected PricewaterhouseCoopers, LLP ("Pricewaterhouse") as the Company's independent auditor for the fiscal year 2007, and the Board is asking the shareholders to ratify that selection. Although current law, rules, and regulations, as well as the charter of the Audit Committee, require the Audit Committee to engage, retain, and supervise the Company's independent auditor, the Board considers the selection of the independent auditor to be an important matter of shareholder concern and is submitting the selection of Pricewaterhouse for ratification by shareholders as a matter of good corporate practice.

Under Arizona law, if a quorum of shareholders is present at the Meeting, the ratification of the selection of PricewaterhouseCoopers as independent auditor for 2007 will require that the votes cast in favor of its ratification

exceed the votes cast against its ratification. Abstentions and broker non-votes are counted for purposes of determining whether a quorum exists at the Meeting but are not counted and have no effect on the results of the vote for independent auditor.

The Board recommends that you vote "FOR" the ratification of the selection of the independent auditor.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

The Compensation Committee is made up of six directors who are independent based upon independence criteria established by our Board, which criteria are in compliance with applicable NYSE listing standards. The Board previously adopted a written charter for the Compensation Committee. The Compensation Committee Charter is available for inspection on the Company's website at www.UNS.com. The Compensation Committee is in compliance with its charter.

The Compensation Committee has reviewed and discussed with management the "Compensation Discussion and Analysis" section required by Item 402(b) of SEC Regulation S-K and contained in this Proxy Statement. Based on such review and discussions, the Compensation Committee recommended to the Board that the "Compensation Discussion and Analysis" section be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2006 and the 2007 Proxy Statement.

Respectfully submitted,

THE COMPENSATION COMMITTEE

Harold W. Burlingame, Chair
Barbara M. Baumann
John L. Carter
Daniel W. L. Fessler
Warren Y. Jobe
Joaquin Ruiz

The following Compensation Discussion and Analysis contains statements regarding future individual and Company performance targets and goals. These targets and goals are disclosed in the limited context of UniSource Energy's compensation programs and should not be understood to be statements of management's estimates of results or other guidance. UniSource Energy specifically cautions investors not to apply these statements to other contexts.

COMPENSATION DISCUSSION AND ANALYSIS

COMPENSATION PHILOSOPHY

Objectives of the Compensation Program

We base our executive compensation policies and decisions with respect to our Named Executives on the achievement of the following objectives:

1. Attract, motivate and retain highly-skilled executives;

2. Link the delivery of compensation to the achievement of critical short- and long-term financial and strategic objectives, creation of shareholder value and provision of safe, reliable and economically available electric and gas service;
3. Align the interests of management with those of our stakeholders and encourage management to think and act like owners, taking into account the interests of the public that the Company serves;
4. Maximize the financial efficiency of the compensation program to avoid unnecessary tax, accounting and cash flow costs; and
5. Encourage management to achieve outstanding results through appropriate means by delivering compensation in a manner consistent with established and emerging corporate governance best practices.

In support of the above objectives, UniSource Energy provides a balanced total compensation program that consists of four components:

- base salary;
- short-term performance-based incentive compensation;
- long-term performance-based incentive compensation; and
- benefits and perquisites.

Each of these components is described in more detail below and in the narrative and footnotes to the supporting tables. The following illustrates how the above objectives are reflected in our compensation program:

Attracting, Retaining and Motivating Executive Talent

In support of our objective to attract, retain and motivate highly-skilled employees, we provide our Named Executives with compensation packages that are competitive with those offered by other electric and gas services companies of comparable size and complexity.

The Compensation Committee generally targets base salary and short-term incentive opportunities, as well as the allocation among those elements of compensation for the Named Executives, at the median market rates of selected comparable companies. Long-term incentive opportunities are targeted at the 75th percentile of such market rates. Target compensation for individual executives range above or below those benchmarks based on a variety of factors, including each executive's skill set and experience relative to the general market, the importance of the position to the Company and the difficulty of replacing the executive, and the executive's past and expected future contribution to our success.

In addition to providing competitive direct compensation opportunities, the Company also provides certain indirect compensation and benefits programs that are intended to assist in attracting and retaining high quality executives. These programs include pension and retirement programs and are described in more detail below and in the narratives that accompany the tables that follow this Compensation Discussion and Analysis section.

Linking Compensation to Performance

Our compensation program seeks to link the actual compensation earned by our Named Executives to their performance and that of the Company. We achieve this goal primarily through two elements of our compensation package: (i) short-term cash awards and (ii) equity-based compensation. To ensure that the most senior executives are held most accountable for achieving our financial, operational and strategic objectives and for creating shareholder value, we believe that the percentage of pay at risk should increase with the level of responsibility within the Company. The target amounts of performance-based pay programs (i.e., cash incentive and equity-based compensation) comprise approximately 55% to 65% of the total direct compensation opportunity for our Named Executives. Non-variable compensation, such as salary and perquisites, are de-emphasized in the total compensation program to reinforce the linkage between compensation and performance.

Aligning the Interests of our Named Executive Officers with Stakeholders

Our compensation program also seeks to align the interests of our Named Executives with those of our key stakeholders, including customers, employees and shareholders. We use the short-term incentive compensation component to focus the Named Executives on the importance of providing safe and reliable customer service, creating a safe work environment for our employees and improving financial performance by linking a significant portion of their short-term cash incentive compensation to achievement of these objectives. We primarily rely on the equity compensation element of our compensation package to align the interests of the Named Executives with those of shareholders through a mix of stock options and stock awards that vest based on the achievement of performance goals set by the Compensation Committee. We also encourage senior executives to accumulate a substantial stake in the Company.

Maximizing the Financial Efficiency of the Program

In structuring the total compensation package for our Named Executives, the Compensation Committee evaluates the accounting cost, cash flow implications and tax deductibility of compensation to mitigate financial inefficiencies to the greatest extent possible. For instance, as part of this process, the Compensation Committee evaluates whether compensation costs are fixed or variable and places a heavier weighting on variable pay elements to calibrate expense with the achievement of operating performance objectives and delivery of value to shareholders. In addition, the Compensation Committee takes into account the objective of having the incentive-based compensation components qualify for tax deductibility under Section 162(m) of the Internal Revenue Code, as amended (the "Code"). See discussion under "Impact of Regulatory Requirements" on page 19. The Compensation Committee also considers the cash flow and share dilution implications of cash versus equity-based incentive plans. In managing overall costs under the variable incentive plans, the Compensation Committee sets annual budgets with regard to total expense and the dilutive impact on shareholders. These budgets are set at levels determined to be reasonable and sustainable by the Company in relation to costs incurred by peer companies.

Adhering to Corporate Governance Best Practices

The Compensation Committee seeks to continually update the executive officer compensation program to reflect corporate governance best practices. For example, the Compensation Committee has established formal stock ownership guidelines that encourage each Named Executive to accumulate a meaningful amount of Company stock. Additionally, equity-based awards contain a "double-trigger" vesting provision, which provides for accelerated vesting in the event of a future change in control only if the executive is adversely impacted by the transaction.

As the Compensation Committee analyzes and discusses executive compensation in its meetings, it considers certain factors for purposes of establishing salaries and variable compensation opportunities. Factors that are considered in its assessment include the following:

- total compensation, taking into account all equity awards granted since the executive started with the Company, total wealth accumulation and future compensation opportunities, as depicted in tally sheets;
- internal pay equity;
- stock ownership and retention policies, including hold-until-retirement policies;
- competitive environment for Named Executives, and what relevant competitors pay; and
- the need to provide each element of compensation and the amounts targeted and delivered.

Benchmarking

To provide a foundation for the executive compensation program, UniSource Energy participates in an annual executive compensation survey of the energy services industry and periodically reviews the senior executive compensation levels and practices among a peer group of companies intended to represent our competitors for business and talent. The peer group is reviewed periodically and includes the 16 electric and gas utility companies named below that are comparable to UniSource Energy in terms of size as measured by annual revenues and market capitalization. UniSource Energy's revenues and market capitalization are generally consistent with the median of the peer companies.

AGL Resources Inc.	DPL Inc.	Northwest Natural Gas Co.	Southern Union Co.
Avista Corp.	Duquesne Light Company	Otter Tail Power Company	Southwest Gas Corp.
CH Energy Group Inc.	El Paso Electric Co.	PNM Resources Inc.	UIL Holdings Corp.
Cleco Corporation	IDACORP Inc.	South Jersey Industries	Westar Energy Inc.

A comprehensive review of UniSource Energy's executive compensation levels and aggregate long-term incentive cost and share usage practices relative to peer group was most recently conducted in October 2005.

The benchmark information is supplemented with information from Frederic W. Cook and Co., Inc., the independent consultant retained by the Compensation Committee, relating to general market trends, changes in regulatory requirements related to executive compensation and emerging best practices in corporate governance.

ELEMENTS OF COMPENSATION

Base Salary

We believe that competitive base salaries are necessary to attract and retain executive talent critical to achieving the Company's business goals. In general, our Named Executives' base salaries are targeted to the median of the benchmark companies described above. However, individual salaries can and do vary from the benchmark median data based on such factors as individual performance, potential for future advancement, the importance of the executive's position to the Company and the difficulty of replacement, current responsibilities, length of time in the current position, and, for recently hired executives, their prior compensation packages.

Increases to Named Executives' base salaries are considered annually by the Compensation Committee. In approving base pay increases for executives other than the CEO, the Compensation Committee also considers recommendations made by the CEO.

In December 2006, the Compensation Committee approved the following base salary increases for the Named Executives for 2007:

Name	*2006 Base Pay*	*Approved 2007 Base Pay*
James S. Pignatelli	$670,000	$695,000
Kevin P. Larson	$290,000	$300,000
Dennis R. Nelson	$290,000	$295,000
Michael J. DeConcini	$290,000	$300,000
Raymond S. Heyman	$290,000	$300,000

Short-Term Incentive Compensation (Cash Incentive Awards)

The Compensation Committee provides for short-term incentive compensation payments under the Performance Enhancement Plan ("PEP") in order to tie a significant portion of the Named Executives' annual compensation to the Company's annual financial and operational performance. Each year the Compensation Committee establishes targets that are expressed as a percentage of salary, objective performance criteria that must be met in order for payouts to be made and other terms and conditions of awards under the PEP. Each of these components is discussed below. We typically approve short-term incentive metrics in the first quarter.

The Compensation Committee generally attempts to align target cash incentive opportunities for each Named Executive with the median rate for equivalent positions at the benchmark companies. In 2006, target incentive opportunities under the PEP for the Named Executives ranged from 50% to 80% of base salary, depending on position and were payable in cash. Depending upon achievement of the objective performance goals, a Named Executive's actual payout may be above or below the targeted amount. The maximum potential award for any participant in the PEP, including the Named Executives, was 150% of the target cash incentive amount. For years prior to 2007, the Compensation Committee had the discretion to increase, reduce or eliminate an award regardless of whether the performance goals applicable to the Named Executive's incentive award have been achieved.

In 2006, the performance criteria approved by the Compensation Committee and applicable to all Named Executives and other non-union employees were earnings per share ("EPS"), cost containment ("O&M") and customer service and core business goals relating to customer service, regulatory, reliability and safety. The customer service and core business goals included, among others, customer service response time average at or below 3 minutes, community service of at least 35,000 hours volunteered by employees, Springerville Unit 3 and Luna generation project implementation, various operational reliability goals, and OSHA incident rates at or below national average. The EPS and O&M goals were weighted 30% each and the operational goals were weighted 40%. The EPS range was $1.65 to $2.05 per basic share, the O&M expense range was $228 million to $238 million, and the customer service and core business goals range was 200 to 600 points (which are calculated in accordance with a formula that takes into account the relative weighting of each customer service or core business goal). Each of the three major goals had an individual threshold, and payouts under the PEP can occur along a range of 15% to 150% of target. These measures and the individual weightings were selected by the Compensation Committee to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence. We believe that the cash incentive compensation plan represents the interests of various stakeholders, including customers, employees, and shareholders.

For 2006 performance, the Company achieved its basic EPS goal at a level of 115% of target, or $1.91 per share, its cost containment goal at 75% of target, or $235.5 million, and its customer service and core business goals at 100% of target, or 400 points. Accordingly, the total weighted achievement level was 97% of target for 2006. In February 2007, the Compensation Committee determined that the cash incentive funding under the PEP would be 100%, with adjustments made to individual Named Executive's awards to reflect individual performance. See Footnote 3 of the Summary Compensation Table for the payouts under the 2006 PEP awards.

In February 2007, the Compensation Committee approved the short-term PEP program for 2007. The structure of the 2007 program remains the same as 2006, but certain changes were made, including replacement of Basic EPS with Diluted EPS and greater emphasis on customer service, safety and core business goals.

Long-Term Incentive Compensation (Equity Awards)

We provide long-term incentives in the form of various types of equity awards to help achieve several key compensation objectives. We believe that equity awards, in tandem with our executive stock ownership guidelines discussed below, encourage ownership of Company stock by executive officers, which in turn aligns the interest of

those officers with the interest of our shareholders. In addition, the vesting provisions applicable to the awards encourage a focus on long-term operating performance, link compensation expense to the achievement of multi-year financial results and help to retain executive officers.

The UniSource Energy Corporation 2006 Omnibus Stock and Incentive Plan (the "2006 Omnibus Plan") was approved by our shareholders in 2006 and permits the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, and performance units. This plan gives the Company flexibility in providing competitive long-term incentive compensation.

Annually, during the first quarter, the Compensation Committee approves the long-term incentive awards to be granted for the upcoming year. This includes the type of equity to be granted, as well as the size of the awards for Named Executives. In determining the type and aggregate size of awards to be provided, as well as the performance metrics that will apply, the Compensation Committee considers the strategic goals of the Company, trends in corporate governance, accounting impact, tax deductibility, cash flow considerations, the impact on EPS and the number of shares that would be required to be allocated for the award and the resulting impact to shareholders.

Long-term incentive opportunities are expressed as a multiple of salary. The long-term incentive multiple is then applied to the Named Executive's base salary to determine the size of the award. The long-term incentive multiple, which is 100% for each Named Executive, was established in 2003 to retain the executives in light of a then pending merger. The value of the Named Executives' long-term incentive multiples, which is generally consistent with the 75th percentile of benchmark practice, has been maintained for the Named Executives to strengthen the retention value of the compensation program following the termination of the proposed merger transaction in 2004. The impact of the proposed merger transaction on executive officer compensation is described in greater detail in "Elements of Post-Termination Compensation – Change in Control".

During 2004 and 2005, the Company did not have shares available for stock awards under a shareholder approved incentive plan so it adopted a cash incentive based long-term incentive plan ("LTIP") during that period. Under the 2004 LTIP, the Named Executives received payouts based on the achievement of three performance goals during 2004, which were EPS, TEP operating cash flow and UniSource Energy consolidated operating cash flow. The achievement level for the 2004 performance period was 120% of target and the Named Executives received payouts beginning in 2005 in three installments under the 2004 LTIP, the last of which is reflected in the Summary Compensation Table below. The 2005-2007 LTIP is based on the achievement of two performance goals, EPS and UniSource Energy consolidated operating cash flow, over the three-year period 2005-2007. Actual 2005 and 2006 results, together with projections for 2007, indicate that the three-year performance results will likely fall short of the threshold payout level.

For 2006, management recommended and the Compensation Committee approved long-term incentive awards consisting of stock options and performance shares. We believe that our long-term incentive program is well-balanced in that it focuses the Named Executives on increasing shareholder value and achieving longer-term financial goals. Options are designed, in part, to reward longer term success in Company performance that is reflected in increases in share price and performance shares are designed, in part, to reward achievement of financial performance objectives whether or not reflected in actual share price in the short term. In addition, performance shares support important financial efficiency objectives by ensuring that cost is variable and incurred by the Company only to the extent that financial goals are achieved.

The 2006-2008 performance share awards are tied to the achievement of Basic EPS (defined as EPS applied to undiluted outstanding shares) and cash flow goals over a three-year performance period. These goals were selected since they are considered to be the most significant drivers of long-term value creation for our shareholders. The goals are equally weighted and the Named Executives can earn 0% to 150% of the target shares based on actual achievement of the goals. Under the 2006-2008 long-term award, a cumulative Basic EPS range of $5.80 to $6.38 and a cumulative cash flow from operations range of $879.6 million to $901.1 million must be achieved over the 2006-2008 period in order to meet their target. For 2006, Basic EPS was $1.91 per share and cash flow was $282.5 million which will contribute towards the cumulative three-year performance period. These targets and goals are

disclosed in the limited context of UniSource Energy's compensation programs and should not be understood to be statements of management's estimates of results or other guidance. UniSource Energy specifically cautions investors not to apply these statements to other contexts. See the Grants of Plan-Based Awards Table on page 22 for the minimum, target and maximum awards for each of the Named Executives.

The 2006-2008 stock option and performance awards were made in May 2006 following shareholder approval of the 2006 Omnibus Plan. Future long-term incentive awards are expected to be granted by the Compensation Committee during the first quarter following the close of the fiscal year. When the Compensation Committee approves grants of plan-based equity awards, the exercise price is set at the market closing price of UniSource Energy common stock on the date that the grant is made, consistent with recent developments in SEC rules and guidelines. Awards are not coordinated with the release of material non-public information.

In addition, the Company does not typically provide for off-cycle stock option grants and has no specific number of shares under the 2006 Omnibus Plan set aside for such grants. However, occasionally in connection with a new hire of an executive, such a grant may be made to the extent approved by the Compensation Committee. The exercise price of any off-cycle option granted to a newly hired executive will be the closing market price on the date that the Compensation Committee approves any such award, consistent with the pricing practices associated with on-cycle plan-based equity awards.

Stock option grants and performance share awards are intended to qualify as performance-based compensation under Section 162(m) of the Code, which ensures that awards granted to the CEO and other Named Executives are tax deductible by the Company.

In March 2007, the Compensation Committee approved awards of stock options and performance shares to the Named Executives under a 2007-2009 stock option and performance award. The terms of the stock options and the design of the performance share plan are similar to the 2006-2008 long-term incentive program described above and in the footnotes to the Grants of Plan-Based Awards Table, although for the 2007-2009 long-term award, Diluted EPS has replaced Basic EPS.

OTHER COMPENSATION

Perquisites

The Company provides Named Executives with limited personal benefits and perquisites. These are not tied to any formal individual or Company performance criteria but are intended to enhance the attraction and overall retention value of the executive compensation program and be responsive to similar benefits provided to executives and other key personnel in other similar companies in the industry. Executive officers, along with managers and certain other supervisory personnel, are provided with the use of a vehicle and related vehicle operating costs of fuel and car insurance are paid for by the Company. In addition, the Company from time to time reimburses certain executives for business or similar social club initiation fees and periodic special assessments. Finally, the Company also reimburses executives for the travel expenses of their spouses incurred in connection with the annual Board strategic retreat. For identification of specific perquisites and associated values that are set forth in accordance with applicable SEC requirements, refer to the Summary Compensation Table on page 20.

Retirement Benefits

Our Named Executives are also eligible to participate in certain employee benefits plans and arrangements offered by the Company. These include the Tucson Electric Power Company 401(k) Plan, the Tucson Electric Power Company Salaried Employees Retirement Plan (the "Retirement Plan"), the Tucson Electric Power Company Excess Benefits Plan (the "Excess Benefits Plan") and the Management and Directors Deferred Compensation Plan (the "DCP"). A description of the pension and other retirement plans is provided under "Elements of Post-Employment Compensation-Retirement and Other Benefits," below.

ELEMENTS OF POST-EMPLOYMENT COMPENSATION

Termination and Change in Control

In 1998, TEP, a wholly owned subsidiary of the Company, entered into Change in Control Agreements ("Change in Control Agreements" or "Agreements") with all of the then Named Executives to help keep them focused on their work responsibilities during the uncertainty that accompanies a change in control, to provide benefits for a period of time following certain terminations of employment after a change in control event or transaction and to help us attract and retain key personnel.

For the purpose of the Agreements, a change in control includes the acquisition of beneficial ownership of 30% of the common stock of UniSource Energy, certain changes in the Board, approval by the shareholders of certain mergers or consolidations or certain transfers of the assets of UniSource Energy. The Agreements provide that each officer shall be employed by TEP or one of its subsidiaries or affiliates, in a position comparable to his current position, with compensation and benefits, which are at least equal to his then current compensation and benefits, for an employment period of five years after a change in control (subject to earlier termination due to the officer's acceptance of a position with another company or termination for cause).

The Agreements are in effect until the later of: (i) five years after the date either TEP or the officer gives written notice of termination of the Agreement, or (ii) if a change in control occurs during the term of the Agreements, five years after the change in control. On March 29, 2004, a change in control occurred for purposes of the Agreements when our shareholders, at a special meeting, approved the acquisition agreement that provided for an affiliate of Saguaro Utility Group L.P. to acquire all of our outstanding shares of common stock.

On March 3, 2005, TEP provided the officers of the Company with written notice of termination of the Agreements effective March 3, 2010, the fifth anniversary of the date of the written notice of termination. In December 2006, the CEO of the Company and one other Named Executive, Dennis R. Nelson, waived all rights they otherwise would have had for the remaining effective period under their Agreements and terminated the Agreements to which they and TEP had been party.

During the remaining term of the Agreements currently in effect, in the event that an officer's employment is terminated by TEP (with the exception of termination due to the officer's acceptance of another position or for cause), or if the officer terminates employment because of a reduction in position, responsibility, compensation or for certain other stated reasons prior to March 3, 2010, the officer is entitled to severance benefits in the form of: (i) a lump sum payment equal to the present value of three times the sum of annual salary and target bonus ("cash severance"), (ii) the present value of the additional amount (including any amount under the Excess Benefits Plan) the officer would have received under the Retirement Plan if the officer had continued to be employed for the five-year period after a change in control occurs, plus (iii) the present value of any employee award under the 2006 Omnibus Plan or any successor plan, which is outstanding at the time of the officer's termination (whether vested or not), prorated based on length of service. Such officer is also entitled to continue to participate in TEP's health, death and disability benefit plans for five years after the termination. The Agreements further provide that TEP will make a payment to the officer to offset any golden parachute excise taxes that may be imposed in accordance with Code sections 280G and 4999. Any payments made in respect of such excise taxes are not deductible by us. Cash severance would also be paid under the Agreements if an officer dies or becomes disabled prior to March 3, 2010. Refer to "Potential Payments upon Termination or Change in Control" on page 27 for quantification of potential amounts payable under the Agreements.

Beginning in 2006, all long-term incentive awards contain a "double trigger" vesting provision, which provides for accelerated vesting only if outstanding awards are not assumed by an acquirer or the Named Executive is terminated without cause within 24 months of a change in control. The double trigger, which is viewed as a corporate governance "best practice", ensures that the Named Executives do not receive accelerated benefits unless they are adversely affected by the change in control.

Other than the Agreements described above, we have not entered into any other severance agreements or employment agreements with any Named Executives except that in December 2006, TEP entered into an employment agreement for a term of six months with Dennis R. Nelson in conjunction with the termination of his Change in Control Agreement. At the time the Company and Mr. Nelson entered into such agreement, Mr. Nelson announced his intention to retire in June 2007. The employment agreement with Mr. Nelson, Senior Vice President, Utility Services, terminates upon his retirement on June 1, 2007. The employment agreement provides that TEP will pay Mr. Nelson a fixed salary of not less than his current annual salary of $295,000, subject to periodic review and increase by the Board of Directors, and for Mr. Nelson's continued participation in TEP's compensation and employee benefit plans. The agreement provides that TEP will pay Mr. Nelson a severance payment in the event that TEP terminates Mr. Nelson's employment for reasons other than cause, disability or death, or, if Mr. Nelson terminates his employment following (1) a material reduction of his responsibilities; (2) a material reduction of compensation; (3) relocation or reassignment beyond 50 miles from the location that he works currently; or (4) certain liquidation, dissolution, consolidation or merger transactions involving the company. Severance is to be paid in a lump sum cash payment and the amount will equal any annual target bonus owing but unpaid for 2006, $300,000 (less any amount paid in respect of the 2006 target bonus), and a prorated annual target bonus for the year of the termination. In addition, the agreement provides that Mr. Nelson will receive service credit for eligibility and benefits purposes until June 1, 2007 and will be entitled to participate in the Company retiree medical plan regardless of the actual date his employment is terminated.

The Compensation Committee and the Board are currently in the process of evaluating future alternatives associated with change-in-control protection that may be offered to Named Executives who have not been party to a Change in Control Agreement. For additional information on amounts that would be payable to those Named Executives who currently have Agreements still in effect, refer to the Potential Payments upon Termination or Change in Control Table on page 27.

Retirement and Other Benefits

Benefits Generally

The Company offers retirement and other core benefits to its employees, including executive officers, in order to provide them with a reasonable level of financial support in the event of illness or injury and to enhance productivity and job satisfaction. The benefits are the same for all employees and executive officers and include medical and dental coverage, disability insurance and life insurance. In addition, the Tucson Electric Power Company 401(k) Plan and the Retirement Plan provide a reasonable level of retirement income reflecting employees' careers with the Company. All employees, including executive officers, participate in these plans; the cost of these benefits (other than the Retirement Plan) is partially borne by the employee, including each executive officer. To the extent that any officer's retirement benefit exceeds Internal Revenue Service ("IRS") limits for amounts that can be paid through a qualified plan, the Company also offers non-qualified retirement plans, including the Excess Benefits Plan and the DCP. These plans provide only the difference between the calculated benefits and the IRS limits.

Tucson Electric Power Company Excess Benefits Plan

The Retirement Plan is subject to Code limitations on the amount of compensation that can be taken into account and on the amount of benefits that can be provided. The Excess Benefits Plan provides retirement benefits to officers in addition to the maximum amount of benefits payable under the Retirement Plan. The Excess Benefits Plan retirement benefit is calculated generally using the same pension formula as the Retirement Plan formula but with some modifications. Compensation for purposes of the Excess Benefits Plan is determined without regard to IRS limits on compensation and by including voluntary salary reductions to the DCP, and any annual incentive payment received under the PEP. The retirement benefit payable from the Excess Benefits Plan is reduced by the benefit payable to that person from the Retirement Plan.

Benefits under the Excess Benefits Plan are provided to officers but, with limited exceptions, are not generally

available to other employees. These benefits are not tied to any formal individual or Company performance criteria but are intended to enhance the attraction and retention value of the executive compensation program and are consistent with similar competitive compensation benefits made available to executives in the industry.

UniSource Energy Corporation Management and Directors Deferred Compensation Plan

The DCP allows participants (which include directors, officers and managers) the opportunity to accumulate tax-deferred capital by allowing them to defer a portion of their pay on a pre-tax basis. A participant may elect to defer a percentage of his salary or any bonus up to 100%.

The DCP provides Named Executives and other participants with the opportunity to defer a portion of their base salary and bonus into various investment alternatives, including UniSource Energy stock units. Additionally, we credit the DCP accounts of executives participating in our 401(k) Plan with the additional amount of UniSource Energy matching contributions that the participant would have been entitled to under our 401(k) Plan but for certain Code limits. We believe this plan assists with our attraction and retention objectives since it provides an industry-competitive and tax-efficient benefit to our executives. The DCP is not funded by the Company and participants have an unsecured contractual commitment by the Company to pay amounts owed under the DCP. Additional details on the DCP are provided in the narrative and footnotes to the Non-Qualified Deferred Compensation Table on pages 26-27.

STOCK OWNERSHIP POLICY

To further support our objective of aligning management and shareholder interests, we adopted a formal stock ownership policy, which encourages all officers to accumulate a substantial ownership stake in Company shares. The policy has the following key features:

- Participants are encouraged to accumulate Company shares with a target value of a multiple of their base salary, ranging from one times base salary for Vice Presidents to five times for our CEO. The Named Executives other than the CEO have a target value equal to three times their base salary.

- If a participant has not yet reached the applicable target ownership requirement, he is expected to retain a portion of the net after-tax shares acquired from any stock option exercise, vesting of restricted stock or payments related to the performance share program. The applicable retention rates are 100% for the CEO, 50% for the other Named Executives and 25% for the other Vice Presidents.

- Unexercised stock options, unvested stock options and unearned performance shares do not count towards meeting the ownership guidelines.

Annually, management provides a report to the Compensation Committee regarding the number and value of the shares held by each officer subject to the guidelines. As of December 31, 2006, all executives who were hired before 2005, including the CEO, have achieved their target ownership level; five officers appointed subsequently are making progress toward meeting the guidelines.

IMPACT OF REGULATORY REQUIREMENTS

Under Section 162(m) of the Code, certain items of compensation paid to the CEO and to each of the other Named Executives in excess of $1,000,000 annually are not deductible for federal income tax purposes unless the compensation is awarded under a performance-based plan approved by the shareholders. With respect to performance-based compensation, Section 162(m) of the Code requires that performance metrics be set within 90 days of the commencement of the performance period. Accordingly, the Compensation Committee schedules its meetings so that the incentive-based compensation programs designed to provide performance-based compensation, within the meaning of Code section 162(m), are approved during the first quarter of the year. To the extent that the Company complies with the performance-based compensation provision of Section 162(m), the awards granted to

the CEO and other Named Executives are tax deductible by the Company.

The Compensation Committee believes that it is in the best interest of the Company to receive maximum tax deductibility for compensation paid to the Named Executives under Section 162(m) of the Code, although to maintain flexibility in compensating Named Executives in a manner designed to promote varying corporate goals, the Compensation Committee may award compensation that is not fully deductible under certain circumstances. The Company's compensation plans reflect the Compensation Committee's intent and general practice to pay compensation that the Company can deduct for purposes of federal income tax. Executive compensation decisions, however, are multifaceted. The Compensation Committee reserves the right to pay amounts that are not tax deductible to meet the design goals of our executive compensation program.

The Compensation Committee also considers other financial implications when developing and implementing the Company's compensation program, including accounting costs, cash flow impact and potential share dilution.

SUMMARY COMPENSATION TABLE—2006

The following table sets forth summary compensation information for the year ended December 31, 2006 for our CEO, our Chief Financial Officer and three other most highly compensated Named Executives:

Name and Principal Position	Year ($)	Salary ($)	Stock Awards ($)(1)	Option Awards ($)(2)	Non-Equity Incentive Plan Compen-sation ($)(3)	Change in Pension Value and Non-Qualified Deferred Comp-ensation Earnings ($)(4)	All Other Compen-sation ($)(5)	Total ($)
James S. Pignatelli Chairman, President and Chief Executive Officer	2006	666,923	95,476	339,742	867,500	210,550	17,646	2,197,837
Kevin P. Larson Senior Vice President and Chief Financial Officer	2006	288,462	41,317	32,671	259,184	74,313	15,352	711,299
Dennis R. Nelson Senior Vice President, Utility Services	2006	288,846	20,668	147,017	248,220	66,113	14,469	785,333
Michael J. DeConcini Senior Vice President and Chief Operating Officer, Transmission and Distribution	2006	288,462	41,317	32,671	265,196	38,573	14,768	680,987
Raymond S. Heyman Senior Vice President and General Counsel	2006	288,462	41,317	155,783	167,000	65,352	14,020	731,934

(1) The amounts included in the "Stock Awards" column represent the compensation expense recognized by the Company for performance share awards granted to the Named Executives in 2006, calculated in accordance with Statement of Financial Accounting Standards share based payment (revised 2004) ("FAS 123R"). The Company's FAS 123R assumptions used in these calculations are set forth on pages 136-140 of our annual report on Form 10-K filed with the SEC on February 28, 2007 and available on the Company's website at www.UNS.com.

(2) The amounts included in the "Option Awards" column represent the compensation expense recognized by the Company for stock option awards granted to the Named Executives in 2006 and a 2005 stock option award to Mr. Heyman, calculated in accordance with FAS 123R. The Company's FAS 123R assumptions used in these calculations are set forth on pages 136-140 of our annual report on Form 10-K filed with the SEC on February 28, 2007 and available on the Company's website at www.UNS.com. Since Mr. Pignatelli and Mr. Nelson are retirement eligible, their accruals were accelerated and expensed in 2006 rather than over a three-year vesting period.

(3) The Non-Equity Incentive Plan Compensation listed on this table reflects the second of three installments associated with the 2004 long-term incentive plan awards plus the payout under the 2006 PEP awards. The 2006 payouts under the 2004 long-term incentive plan awards were as follows: Mr. Pignatelli, $250,500; Mr. Larson, $92,184; Mr. Nelson, $110,220; Mr. DeConcini, $98,196. The PEP awards included in this column were paid during the first quarter of 2007 and are as follows: Mr. Pignatelli, $617,000; Mr. Larson, $167,000; Mr. Nelson, $138,000; Mr. DeConcini, $167,000; and Mr. Heyman, $167,000.

(4) This column reflects the change in the actuarial present value of the accumulated benefit under all defined benefit plans (the Retirement Plan and Excess Benefits Plan). Our non-qualified DCP does not provide participants with above-market earnings. Our non-qualified DCP offers participants a menu of investment options and these accounts provide participants with a return based on their selection of investment opportunities.

(5) The amounts in the "All Other Compensation" column include the following payments that we made on behalf of the Named Executives:

Name	Year	Car Benefit ($)	Qualified Plan 401(k) Matching Contributions ($)	Non-Qualified Plan 401(k) Matching Contributions ($)	Club Memberships ($)	Spouse Travel ($)	Total ($)
James S. Pignatelli	2006	1,566	9,900	5,100	1,080	0	17,646
Kevin P. Larson	2006	2,062	9,900	3,081	0	309	15,352
Dennis R. Nelson	2006	1,471	9,900	3,098	0	0	14,469
Michael J. DeConcini	2006	398	9,900	3,081	1,080	309	14,768
Raymond S. Heyman	2006	684	9,900	3,081	0	355	14,020

The "Car Benefits," "Club Memberships," and "Spouse Travel" columns include the incremental cost to the Company of such benefits. For the car benefit, the incremental cost includes the cost of fuel and maintenance of a vehicle provided to the Named Executive for personal use. The Company also pays for the auto insurance, but that cost is very small and cannot be quantified because the insurance is provided through a comprehensive policy that covers many insurable risks and the underwriters do not provide any cost allocation information. Spouse travel costs include airfare for the Named Executives' spouses for the annual Board retreat.

We have no employment agreements with our Named Executives other than a 6-month employment agreement with Mr. Nelson, which will expire in June 2007 when Mr. Nelson will be retiring. See discussion in "Elements of Post-Employment Compensation-Termination and Change in Control" at pages 17-18.

GRANTS OF PLAN-BASED AWARDS—2006

The following table sets forth information regarding plan-based awards to our Named Executives in 2006. The compensation plans under which the grants in the following table were made are generally described in the "Compensation Discussion and Analysis" section, beginning on page 10 and include the UniSource Energy PEP, which provides for non-equity (cash) performance awards, and the 2006 Omnibus Plan, which provides for equity-based performance awards including stock options and performance shares.

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards (1)			Estimated Future Payouts Under Equity Incentive Plan Awards (2)			All Other Option Awards: Number of Securities Under-lying Options (#)(3)	Exercise or Base Price of Option Awards ($/Sh) (4)	Closing Market Price on Grant Date ($/Sh) (4)	Grant Date Fair Value of Awards ($)(5)
		Thresh -old ($)(1)	Target ($)	Maxi-mum ($)	Thresh -old (#)	Target (#)	Maxi-mum (#)				
James S. Pignatelli		268,000	536,000	804,000							
	5/6/2006				5,580	11,160	16,740				316,832
	5/6/2006							46,010	30.55	30.57	339,742
Kevin P. Larson		72,500	145,000	217,500							
	5/6/2006				2,415	4,830	7,245				137,124
	5/6/2006							19,910	30.55	30.57	147,017
Dennis R. Nelson		72,500	145,000	217,500							
	5/6/2006				2,415	4,830	7,245				137,124
	5/6/2006							19,910	30.55	30.57	147,017
Michael J. DeConcini		72,500	145,000	217,500							
	5/6/2006				2,415	4,830	7,245				137,124
	5/6/2006							19,910	30.55	30.57	147,017
Raymond S. Heyman		72,500	145,000	217,500							
	5/6/2006				2,415	4,830	7,245				137,124
	5/6/2006							19,910	30.55	30.57	147,017

(1) The amounts shown in this column reflect the range of payouts (50%-150%) targeted for 2006 performance

under the Company's PEP, as described in the "Short-Term Incentive Compensation" section of the Compensation Discussion and Analysis above. These amounts are based on the individual's current salary and position. The amount of cash incentive actually paid under the PEP for 2006 is reflected in the Summary Compensation Table above.

(2) The amounts shown in this column reflect the range (50%-150%) of grants in the form of performance shares targeted for 2006 performance under the 2006 Omnibus Plan for long-term incentive compensation, as described in the "Long-Term Incentive Compensation" section of the Compensation Discussion and Analysis above.

(3) Stock options granted under the 2006 Omnibus Plan are described in the Outstanding Equity Awards at Fiscal Year-End Table below. Options are granted at 100% of the fair market value on the date of grant; they vest in one-third increments over a three year period and expire after 10 years.

(4) Exercise price for the May 5, 2006 stock option award was $30.55, which was the average of the high and the low price of the Company's common stock on the NYSE on the grant date. The definition of the "Fair Market Value" in the UniSource Energy 2006 Omnibus Plan was amended in September 2006, from the average of the high and the low prices to the close on the date of grant to conform to new SEC rules and guidelines.

(5) This amount has been determined in accordance with FAS 123R based on the fair value of our common stock as of the grant date of $30.55 per share. For Mr. Nelson, 50% of the amount reflected in this column for his performance share grant is expected to be forfeited because of his retirement in June 2007.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END – 2006

The following table summarizes the number of securities underlying outstanding plan awards for each Named Executive as of December 31, 2006:

	Option Awards (1)				Stock Awards	
Name	**Number of Securities Underlying Unexercised Options (#) Exercisable**	**Number of Securities Underlying Options (#) Unexer-cisable**	**Option Exercise Price ($)**	**Option Expiration Date**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(2)**
James S. Pignatelli	**16,800**		**14.44**	**6/26/2007**		
	58,246		**15.56**	**7/9/2008**		
	114,500		**12.28**	**7/16/2009**		
	175,000		**15.28**	**8/3/2010**		

	150,000		17.91	8/2/2011		
	150,000		18.12	1/2/2012		
	21,226		17.84	5/9/2013		
		46,010	30.55	5/5/2016		
					8,370	305,756
Kevin P. Larson	6,200		15.56	7/9/2008		
	4,500		12.28	7/16/2009		
	17,000		15.28	8/3/2010		
	20,000		17.91	8/2/2011		
	35,000		18.12	1/2/2012		
	7,783		17.84	5/9/2013		
		19,910	30.55	5/5/2016		
					3,623	132,330
Dennis R. Nelson		19,910	30.55	5/5/2016		
					3,623	132,330
Michael J. DeConcini	4,000		15.56	7/9/2008		
	8,900		12.28	7/16/2009		
	40,000		15.28	8/3/2010		
	30,000		17.91	8/2/2011		
	40,000		18.12	1/2/2012		
	8,137		17.84	5/9/2013		
		19,910	30.55	5/5/2016		
					3,623	132,330
Raymond S. Heyman	16,667	33,333	33.55	9/15/2015		
		19,910	30.55	5/5/2016		
					3,623	132,330

(1) All options listed above vest at a rate of 33 1/3% per year over the first three years of the 10-year option term.

(2) Represents the market value of unearned performance shares calculated based on the prorated achievement of the EPS goal at target and the cash flow goal at threshold, taking into account the closing Company stock market price on December 31, 2006.

OPTION EXERCISES AND STOCK VESTED

The following table includes certain information with respect to the options exercised by our Named Executives during the year ended December 31, 2006:

	Option Awards	
Name	Number of Shares Acquired on Exercise (#)(1)	Value Realized on Exercise ($)(2)
James S. Pignatelli	13,109	224,164
Dennis R. Nelson	163,952	2,497,882
Michael J. DeConcini	3,971	68,281

(1) Of shares exercised, the following amounts were due to options that otherwise would have expired during the year: James S. Pignatelli, 13,109 and Michael J. DeConcini, 3,971. Mr. Pignatelli and Mr. DeConcini retained all of the shares acquired through the exercise of the options indicated above.

(2) For options that are exercised in cashless transactions, we base this value on the spread between the exercise price and the actual price at which the shares of common stock are sold in the market. For options that are exercised and retained by the Named Executive, we base this value on the spread between the exercise price and the actual market price of our common stock at the time of exercise.

PENSION BENEFITS

The following table shows the present value of accumulated benefits payable to each of the Named Executives, including the number of years of service credited to each such Named Executive, under each of the Retirement Plan and the Excess Benefits Plan determined using interest rate and mortality rate assumptions consistent with those used in the Company's financial statements as set forth on pages 131-136 of the Company's Annual Report on Form 10-K. Information regarding the Retirement Plan and the Excess Benefits Plan can be found under the heading "Retirement and Other Benefits" on page 18.

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During Last Fiscal Year ($)
James S. Pignatelli	Tucson Electric Power Salaried Employees Retirement Plan (1)	12.3	414,610	0
	Tucson Electric Power Excess Benefits Plan	12.3	3,934,623	0
Kevin P. Larson	Tucson Electric Power Salaried Employees Retirement Plan (1)	21.7	334,857	0
	Tucson Electric Power Excess Benefits Plan	21.7	302,193	0
Dennis R. Nelson	Tucson Electric Power Salaried Employees Retirement Plan (1)	28.4	542,386	0
	Tucson Electric Power Excess Benefits Plan	28.4	481,335	0
Michael J. DeConcini	Tucson Electric Power Salaried Employees Retirement Plan (1)	17.9	182,738	0
	Tucson Electric Power Excess Benefits Plan	17.9	242,757	0
Raymond S. Heyman	Tucson Electric Power Salaried Employees Retirement Plan (1)	1.3	21,453	0
	Tucson Electric Power Excess Benefits Plan	1.3	57,125	0

(1) The Retirement Plan is intended to meet the requirements of a qualified benefit plan for Code purposes, and is funded by the Company and made available to all eligible employees. The Retirement Plan provides an annual income upon retirement based on the following formula:

1.6% x years of service (up to 25 years) x final average pay

Final average pay is calculated as the average of basic monthly earnings on the first of the month following the employee's birthday during the five consecutive plan years in which basic monthly earnings were the highest, within the last 15 plan years before retirement. Years of service are based on years and months of employment. A Retirement Plan participant is fully vested in his or her retirement benefit after five years of service. The maximum benefit available under the Retirement Plan is an annual income of 40% of final average pay (as defined above). Plan compensation for purposes of determining final average pay is limited by IRS compensation limits under Code Section 401(a)(17). For 2006, the limit was $220,000 in annual income.

NON-QUALIFIED DEFERRED COMPENSATION

UniSource Energy sponsors the DCP for directors, officers and certain other employees of UniSource Energy. Under the DCP, employee participants are allowed to defer up to 100% of base salary and cash bonuses and non-employee director participants are allowed to defer up to 100% of their cash compensation. This deferral plan also allows the executive employee participants to obtain the 401(k) Company match beyond the IRS-prescribed contribution and salary limitations of the Company's 401(k) Plan. The Company makes contributions to the DCP coincident with the deferrals made by the participants. The deferrals are used to purchase trust owned life insurance which is held in a rabbi trust. The deferred amounts are valued daily as if invested in one or more of a number of investment funds, each of which may appreciate or depreciate in value over time. The choice of investment funds is determined by the individual participant.

Name	Executive Contributions in Last Fiscal Year ($)(1)	Registrant Contributions in Last Fiscal Year ($)	Aggregate Earnings in Last Fiscal Year ($)(2)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last Fiscal Year End ($)
James S. Pignatelli	**120,000**	**4,550**	**234,262**	**0**	**1,575,648**
Kevin P. Larson	**0**	**1,961**	**5,635**	**0**	**33,963**
Dennis R. Nelson	**0**	**3,250**	**14,759**	**0**	**97,504**
Michael J. DeConcini	**0**	**2,456**	**3,554**	**0**	**21,602**

(1) Represents contributions to the DCP by the Named Executives during the year. These amounts are included in the salary column of the Summary Compensation Table above.

(2) Represents the total market based earnings (losses) for the year on all deferred compensation under the plan based on the investment returns associated with the investment choices made by the Named Executive.

The following table shows the deemed investment options available, and the annual rate of return for the calendar year ended December 31, 2006, under the DCP.

Name of Fund	Rate of Return	Name of Fund	Rate of Return
Fidelity Retirement Money Market	4.82%	Fidelity Spartan Us Equity Index	15.72%
Fidelity Intermediate Bond	4.26%	Fidelity Growth Company	9.56%
Janus Flexible Bond	4.12%	Fidelity Low Price Stock	17.76%
Fidelity Asset Manager	9.19%	Janus Worldwide	17.90%
Fidelity Equity-Income	19.81%	UniSource Energy Corporation Stock	20.12%
Fidelity Magellan	7.22%		

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

The following table and summary set forth potential payments payable to our current Named Executives upon termination of employment or a change in control. The table below reflects amounts payable to our Named Executives assuming their employment was terminated on December 31, 2006:

Name	If Retirement or Voluntary Termination Occurs (1)	If "Change In Control" Termination Occurs ($) (2)	If Death or Disability Occurs ($) (3)
James S. Pignatelli	0	0	275,140
Kevin P. Larson	0	2,770,779	119,062
Dennis R. Nelson	0	0	119,062
Michael J. DeConcini	0	2,758,085	119,062
Raymond S. Heyman	0	0	218,394

(1) In the event of retirement or voluntary termination, each of the Named Executives would be entitled to receive vested and accrued benefits payable from the Retirement Plan and the Excess Benefits Plan, but no form or amount of any such payment would be increased or otherwise enhanced nor vesting accelerated with respect to such plans. In addition, no accelerated vesting of options or performance shares would occur. Retirement Plan and Excess Benefits Plan information for the Named Executives is set forth in the Pension Benefits Table above. Mr. Heyman is not vested in the retirement plans as of December 31, 2006.

(2) If a change in control occurs, and an officer's employment is terminated by TEP (other than due to the officer's acceptance of another position or for cause), or if the officer terminates employment because of a reduction in salary, responsibility, compensation or for certain other stated reasons, the officer is entitled to severance benefits. These include: a) severance payout, b) pro-rated bonus, c) accelerated vesting of stock options, d) performance shares payout, e) enhanced retirement benefits, f) medical benefits continuation, and g) tax gross-up. In December 2006, James S. Pignatelli and Dennis R. Nelson, waived all rights under their Change in Control Agreements and terminated the Agreements to which they and TEP had been party. Mr. Heyman does not have a Change in Control Agreement. For additional discussion on change in control agreements, refer to "Elements of Post Employment Compensation-Termination and Change in Control" on page 17 in the "Compensation Discussion and Analysis" section.

(3) Amounts in this column reflect the value of unvested options that would be accelerated upon the death or disability of the Named Executives. Amounts are calculated based on the difference between the market price of common stock at December 31, 2006 and the exercise price for all unvested options. There is no acceleration of performance shares. In addition, in the event of death, the Named Executive's survivor would be entitled to receive a death benefit in the form of a lump sum or survivor annuity which is principally funded from the Retirement Plan and Excess Benefits Plan. The amount payable to the survivor would be less than the amount that would otherwise have been payable to the Named Executive had the Named Executive survived and received retirement benefits under the Retirement Plan and Excess Benefits Plan. There would be no enhancements as to form, amount or vesting of such benefits in the event of a Named Executive's death. The survivor would also receive life insurance proceeds from the life insurance coverage provided by the Company under the employee life insurance benefit.

In addition, in the case of a termination of Mr. Nelson's employment for reasons other than cause, disability or death, or if Mr. Nelson terminates his employment following (1) a material reduction of his responsibilities, (2) a material reduction of compensation, (3) relocation or reassignment beyond 50 miles from the location where he currently works, or (4) certain liquidation, dissolution, consolidation or merger transactions involving the Company, Mr. Nelson will be entitled to certain severance benefits. These benefits are described in "Elements of Post-Employment Compensation – Termination and Change in Control" on page 17.

EQUITY COMPENSATION PLAN INFORMATION

Equity Compensation Plans

Our only equity-based compensation plan that has not been approved by shareholders is the DCP. Shareholder approval of the DCP has not been required because the provisions of the DCP permit the Company to payout deferred shares accumulated under the DCP in the form of cash. Under the DCP, certain eligible officers and other employees selected for participation, and non-employee members of the Board, may elect to defer a percentage of the compensation or fees that would otherwise become payable to the individual for his services to us. We also credit DCP accounts of employees participating in our 401(k) Plan with the additional amount of UniSource Energy matching contributions that the participant would have been entitled to under the 401(k) Plan if certain Code limits did not apply to limit the amount of UniSource Energy matching contributions made under the 401(k) Plan. Each participant in the DCP may elect that his deferrals be credited in the form of deferred shares instead of cash. Deferred shares are bookkeeping entries that, when payable, will be paid in the form of an

equivalent number of shares of UniSource Energy common stock, subject to shareholder approval prior to the issuance of any such shares, or in cash if the Company so elects. Deferred shares accrue dividend equivalents, credited in the form of additional deferred shares, as dividends are paid by UniSource Energy on its issued and outstanding common stock. Each participant elects the time and manner of payment (lump sum or installments) of his deferred shares under the DCP. Any shares used to satisfy our common stock obligations under the DCP will be shares that have been purchased on the open market. To date, payment of deferred amounts have been only in the form of cash.

Equity Compensation

The following table sets forth information as of December 31, 2006, with respect to UniSource Energy's equity compensation plans.

Plan Category	Number of Shares of UniSource Energy Common Stock to be Issued Upon Exercise of Outstanding Options and Rights	Weighted-Average Exercise Price of Outstanding Options	Number of Shares of UniSource Energy Common Stock Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Shares Reflected in the First Column)
Equity Compensation Plans Approved by Shareholders (1)	1,662,742 (2)	$18.59 (3)	2,020,778 (4)
Equity Compensation Plans Not Approved by Shareholders	60,292 (5)	--	-- (6)
Total	1,723,034	--	--

(1) The equity compensation plans approved by shareholders are the UniSource Energy Corporation 1994 Omnibus Stock and Incentive Plan ("1994 Stock and Incentive Plan"), the UniSource Energy Corporation 1994 Outside Director Stock Option Plan (the "1994 Directors Plan") and the 2006 Omnibus Plan. The 1994 Stock and Incentive Plan and the 1994 Directors Plan were superseded by the 2006 Omnibus Plan. The 1994 plans remain in effect until all awards have expired or terminated or shall have been exercised or fully vested, and any stock thereto shall have been purchased or acquired.

(2) Includes options outstanding as to 1,388,328 shares, stock units, dividend equivalent stock units and restricted stock units (payable in an equivalent number of shares) outstanding as to 274,414 shares.

(3) Calculated based on the outstanding options and exclusive of outstanding stock units.

(4) The 1994 Stock and Incentive Plan expired in accordance with its terms, effective February 3, 2004. On March 30, 2006, the Compensation Committee terminated the 1994 Directors Plan effective January 1, 2006, contingent upon shareholder approval of the 2006 Omnibus Plan. The Compensation Committee further resolved that no awards would be issued under the 1994 Directors Plan after December 31, 2006 (once the 2006 Omnibus Plan was adopted). Awards authorized under the 1994 Directors Plan include options, restricted stock, stock units

and dividend equivalents. The 2006 Omnibus Plan was approved by shareholders in May 2006. Both the 1994 Stock and Incentive Plan and the 1994 Directors Plan remain nominally in effect with respect to currently outstanding awards. No shares that were available to be issued under the 1994 Directors Plan at the time of its termination are available for awards under the 2006 Omnibus Plan with respect to awards that are forfeited, terminated, canceled or expired.

(5) Deferred shares credited under the DCP.

(6) There is no explicit share limit under the DCP. The number of shares to be delivered with respect to the DCP in the future depends on the levels of fees and compensation that participants elect to defer under the DCP. Any UniSource Energy shares used to satisfy our common stock obligations under the DCP will be shares that have been purchased on the open market.

DIRECTOR COMPENSATION

The following table summarizes the compensation earned by non-employee directors of the Company for the year ended December 31, 2006:

Name (1)	**Fees Earned or Paid in Cash ($)(2)**	**Stock Awards ($) (3)(4)(5)(6)**	**Total ($)**
Lawrence J. Aldrich	**44,000**	**40,000**	**84,000**
Barbara M. Baumann	**51,000**	**40,000**	**91,000**
Larry W. Bickle	**43,000**	**55,000**	**98,000**
Elizabeth T. Bilby	**44,000**	**40,000**	**84,000**
Harold W. Burlingame	**52,000**	**55,000**	**107,000**
John L. Carter	**58,000**	**60,000**	**118,000**
Robert A. Elliott	**53,000**	**50,000**	**103,000**
Daniel W. L. Fessler	**47,000**	**40,000**	**87,000**
Kenneth Handy	**53,000**	**58,333**	**111,333**
Warren Y. Jobe	**51,000**	**56,667**	**107,667**
Joaquin Ruiz	**43,000**	**40,000**	**83,000**

(1) Mr. James S. Pignatelli, the President and CEO, is not included in this table as he is an employee of the Company and thus receives no compensation for his service as director. The compensation received by Mr. Pignatelli as an employee of the Company is shown in the Summary Compensation Table.

(2) In 2006, each non-employee director received a $20,000 annual cash retainer, $1,000 for each Board meeting attended and $1,000 for each committee meeting attended. For each of Lawrence J. Aldrich, Barbara M. Baumann, Elizabeth T. Bilby, Harold W. Burlingame, Kenneth Handy and Joaquin Ruiz, 100% of fees earned in 2006 were deferred into the DCP.

(3) Each non-employee director received an annual restricted stock unit award valued at $40,000 in 2006. Values reflected in the table are consistent with FAS 123R grant date fair value. The directors were awarded 1,309.5 restricted stock units on May 5, 2006, the date of the annual shareholder meeting, at a fair market value share price of $30.55. The restricted stock unit awards vest after one year and are distributed in January following termination of Board Service. The award price for the annual director equity award was the average of the high and the low of the Company's common stock on the NYSE on the award date. The definition of the "Fair Market Value" in the 2006 Omnibus Plan was amended in September 2006, from the average of the high and the low price to the close on the date of grant in order to conform to new SEC rules and guidelines.

(4) The non-employee director committee chairpersons and Lead Director received retainers in the form of restricted stock units in 2006. The chairperson and Lead annual retainers were as follows: Audit and Lead Director, $20,000; all other committee chairs, $15,000.

(5) As of December 31, 2006, Mr. Aldrich held 4,020 stock units (including dividend equivalent stock units); Mrs. Baumann held 2,513 stock units (including dividend equivalent stock units). Mr. Bickle held 3,147 stock units (including dividend equivalent stock units); Mrs. Bilby held 4,448 stock units (including dividend equivalent stock units); Mr. Burlingame held 5,163 stock units (including dividend equivalent stock units); Mr. Carter held 3,785 stock units (including dividend equivalent stock units); Mr. Fessler held 3,078 stock units (including dividend equivalent stock units); Mr. Handy held 5,295 stock units (including dividend equivalent stock units); Mr. Jobe held 4,817 stock units (including dividend equivalent stock units); and Mr. Ruiz held 2,513 stock units (including dividend equivalent stock units).

(6) As of December 31, 2006, Mr. Aldrich held 8,358 stock options; Mr. Bickle held 11,558 stock options; Mrs. Bilby held 11,558 stock options; Mr. Burlingame held 11,558 stock options; Mr. Carter held 11,558 stock options; Mr. Elliott held 1,196 stock options; Mr. Fessler held 2,358 stock options; Mr. Handy held 6,358 stock options; and Mr. Jobe held 6,358 stock options.

In December 2006, the Board approved certain changes to the compensation of Board members, effective January 1, 2007. As a result, in 2007, each of the Board members will receive an annual cash retainer in the amount of $40,000; the Lead Director will receive a cash retainer of $20,000; the Audit Chair will receive a $10,000 cash retainer, the Compensation and Corporate Governance Committee Chairs will receive $7,500 cash retainers and all other committee Chairs will receive $5,000 cash retainers. Meeting fees of $1,000 per meeting attended (including committee meetings) will remain the same as in 2006. In addition, each director will receive an annual equity compensation amount equal to $45,000 in restricted stock units, which after a one year vesting period will convert to deferred stock units payable one year after retirement or termination of Board service.

CORPORATE GOVERNANCE

Board Meetings

In 2006, the Board held a total of seven regular and special meetings. Each director attended at least 75% of the aggregate total of Board meetings and meetings of committees of which they are a member. Additionally, the non-management Directors met at regularly scheduled executive sessions without management present. Mr. Carter, a non-management director, presided over and was the Lead Director at these executive sessions.

The Company does not have a formal policy with respect to attendance of Board members at annual meetings of shareholders, but encourages such attendance. All of the Board members attended the 2006 Annual Meeting.

Board Communication

Shareholders or other interested parties wishing to communicate with the Board, the non-management directors or any individual director may contact the Lead Director by mail, addressed to UniSource Energy Lead Director, c/o Corporate Secretary, UniSource Energy Corporation, One South Church Avenue, Suite 2030, Tucson, Arizona 85701. The communications will be kept confidential and forwarded to the Lead Director. Communications received by the Lead Director will be forwarded to the appropriate director(s) or to an individual non-management director.

Shareholders or other interested parties wishing to communicate with the Board regarding non-financial matters may contact the Chairperson of the Corporate Governance and Nominating Committee either by mail, addressed to Chairperson, Corporate Governance and Nominating Committee, UniSource Energy Corporation, P.O. Box 31771, Tucson, Arizona 85751-1771, or by e-mail at unscorpgov@earthlink.net. Shareholders or other interested parties wishing to communicate with the Board regarding financial matters may contact the Chairperson of the Audit Committee either by mail, addressed to Chairperson, Audit Committee, UniSource Energy Corporation, P.O. Box 30201, Tucson, Arizona 85751-0201, or by e-mail at unscorpaudit@earthlink.net.

Items that are unrelated to a director's duties and responsibilities as a Board member may be excluded from consideration, including, without limitation, solicitations and advertisements, junk mail, product-related communications, job referral materials such as resumes, surveys and material that is determined to be illegal or otherwise inappropriate.

DIRECTOR INDEPENDENCE CRITERIA

The Board has adopted Director Independence Standards to comply with NYSE rules for determining independence, among other things, in order to determine eligibility to serve on the Audit Committee, the Compensation Committee and the Corporate Governance and Nominating Committee. The Director Independence Standards, amended as of February 9, 2007, are available on our website at www.UNS.com and are available in print to any shareholder who requests it.

No director may be deemed independent unless the Board affirmatively determines, after due deliberation, that the director has no material relationship with the Company either directly or as a partner, shareholder or officer of an organization that has a relationship with the Company. In each case, the Board broadly considers all the relevant facts and circumstances from the standpoint of the director as well as from that of persons or organizations with which the director has an affiliation and applies these standards.

Annually, the Board determines whether each director meets the criteria of independence. Based upon the foregoing criteria, the Board has deemed each director to be independent, with the exceptions of Mr. Bickle, Ms. Bilby and Mr. Pignatelli. In December 2006, the Board reviewed the independence criteria in connection with a reassessment of the independence status of Mr. Aldrich. In considering whether Mr. Aldrich is independent, the Board considered his prior relationship with Valley Ventures III, LP, a venture capital fund in which Millennium has invested. Mr. Aldrich had been a general partner of the company that manages Valley Ventures III, LP through December 2005, at which time Mr. Aldrich terminated his role and interest as a general partner, but maintained a non-voting financial interest in Valley Ventures III, LP. As a result of the termination of his role as a general partner, the Board concluded that the relationship no longer precluded the determination that he is

independent. As a result of those deliberations and the application of the independence criteria, the Board determined that Mr. Aldrich is now independent. For each other director who is deemed independent, there were no other transactions, relationships or arrangements that were considered by the Board in determining that the director is independent. See "Transactions with Management and Others" below.

Board Committees

The Corporate Governance and Nominating Committee

The Corporate Governance and Nominating Committee reviews and recommends corporate governance principles, interviews potential directors and nominates and recommends to the shareholders and directors, as the case may be, qualified persons to serve as directors. The Corporate Governance and Nominating Committee also reviews and recommends membership for all the committees to the Board and reviews applicable rules and regulations relating to the duties and responsibilities of the Board. Our Corporate Governance and Nominating Committee held four meetings in 2006 and was in compliance with its written charter.

The Corporate Governance and Nominating Committee identifies and considers candidates supplied by shareholders and Board members. The Corporate Secretary, as directed by the Corporate Governance and Nominating Committee, prepares portfolios for candidates that include confirmation of the candidate's interest, independence, biographical information, review of business background and experience and reference checks. The Corporate Governance and Nominating Committee then evaluates candidates using, in large part, the criteria set forth in the next paragraph and any other criteria the Corporate Governance and Nominating Committee deems appropriate, and conducts a personal interview with each candidate. Upon completion of this process, formal invitations are extended to accept election to the Board.

The Corporate Governance and Nominating Committee has not adopted specific minimum qualifications with respect to a committee-recommended Board nominee, but desirable qualifications are set forth in the Corporate Governance Guidelines and include prior community, professional or business experience that demonstrates leadership capabilities, the ability to review and analyze complex business issues, the ability to effectively represent the interests of our shareholders while keeping in perspective the interests of our customers, the ability to devote the time and interest required to attend and fully prepare for all regular and special Board meetings, the ability to communicate and work effectively with the other Board members and personnel and the ability to fully adhere to any applicable laws, rules or regulations relating to the performance of a director's duties and responsibilities.

While no formal policy exists, the Corporate Governance and Nominating Committee does consider recommendations for Board nominees received from our shareholders. The deadline for consideration of recommendations for next year's annual meeting of the shareholders is December 4, 2007. Recommendations must be in writing and include detailed biographical material indicating the candidate's qualifications and a written statement from the candidate of his willingness and availability to serve. Recommendations should be directed to the Corporate Secretary, UniSource Energy Corporation, One South Church Avenue, Suite 1820, Tucson, Arizona 85701. The Board will consider nominees on a case-by-case basis and does not believe a formal policy is warranted at this time due to a manageable volume of nominations.

Each member of our Audit Committee, Compensation Committee and Corporate Governance and Nominating Committee is independent based upon independence criteria established by our Board, which criteria are in compliance with applicable NYSE listing standards.

Compensation Committee

The Compensation Committee operates under the provisions of a committee charter, which can be found at www.UNS.com. The Compensation Committee Charter can be revised by action taken by the Compensation Committee. Under the terms of its charter, the Compensation Committee is required to consist of not fewer than three members of the Board who meet the independence requirements of the NYSE. In 2006, the Compensation Committee had six members who met those independence requirements.

In 2006, the Compensation Committee held six formal meetings, most of which were followed by an executive session in which management did not participate. The Compensation Committee Chair sets the agenda for each meeting, and in advance of each meeting reviews the agenda with management. The annual schedule of meetings is approved by the Board during the fourth quarter for the following year. In connection with Compensation Committee meetings, each Compensation Committee member receives a briefing book prior to each meeting that details each topic to be considered. The Compensation Committee Chair reports to the Board on Compensation Committee decisions and key actions following each meeting. The Compensation Committee members also complete a written assessment of the Compensation Committee's performance, with the last such assessment completed in September 2006.

The Board of Directors has delegated authority to the Compensation Committee to set CEO compensation levels, and to review and approve compensation for all of the Company's executives, including any equity compensation awarded under the 2006 Omnibus Plan. Under the terms of its charter, the Compensation Committee may delegate certain actions to management of the Company in connection with executive compensation. Day-to-day administration of director and executive compensation matters has been delegated to certain Company management personnel, with oversight provided by the Compensation Committee.

Compensation Consultant

The Compensation Committee has retained the services of Frederic W. Cook and Co., Inc. ("Cook"), a nationally recognized compensation consulting firm that serves as an independent advisor in matters related to executive compensation and benefits and director compensation. Representatives from Cook are available to Compensation Committee members on an ongoing basis and attend Compensation Committee meetings, as requested, either in person or telephonically. The Compensation Committee has sole discretion over the terms and conditions of the retention of consultants it retains. Cook maintains no other economic relations with the Company and does not provide any services to the Company other than those provided directly to the Compensation Committee.

The Compensation Committee Chair customarily provides assignments to Cook. In its role as executive compensation consultant to the Compensation Committee, Cook assists with peer group selection, the benchmarking of individual compensation levels, and the design of incentive plans and other compensation arrangements in which Company management participates. In furnishing this assistance, Cook provides competitive data and technical considerations, and recommends changes to the pay program and pay levels for consideration by the Compensation Committee.

Role of Executives in Establishing Compensation

Certain executives, including the CEO, the Chief Financial Officer ("CFO") and the General Counsel to the Company, routinely attend regular sessions of Compensation Committee meetings. The CEO makes recommendations to the Compensation Committee with respect to changes in compensation for senior executive positions (other than the CEO) and payouts under the annual incentive plan. The CEO also makes suggestions to the Compensation Committee regarding the design of incentive plans and other programs in which senior management participates.

The CFO provides information regarding short-term and long-term compensation targets, as well as updates on the progress of short- and long-term objectives. Additional Company personnel with expertise in and responsibility for compensation and benefits provide information regarding executive and director compensation, including cash compensation, equity awards, pensions, deferred compensation and other related information.

The Audit Committee

The Audit Committee reviews current and projected financial results of operations, selects a firm of independent registered public accountants to audit our financial statements annually, reviews and discusses the scope of such audit, receives and reviews the audit reports and recommendations, transmits its recommendations to the Board, reviews our accounting and internal control procedures with our internal audit department from time to time, makes recommendations to the Board for any changes deemed necessary in such procedures and performs such other functions as delegated by the Board. Our Audit Committee held seven meetings in 2006 and was in compliance with its written charter, as amended on December 2, 2005 and attached to this Proxy Statement as Appendix A.

Upon the recommendation of the Audit Committee, our Board adopted a Code of Ethics for our directors, officers and employees.

The Finance Committee

The Finance Committee reviews and recommends to the Board long-range financial policies, objectives and actions required to achieve those objectives. Specifically, the Finance Committee reviews capital and operating budgets, current and projected financial results of operations, short-term and long-range financing plans, dividend policy, risk management activities and major commercial banking, investment banking, financial consulting and other financial relations of UniSource Energy. Our Finance Committee held four meetings in 2006 and was in compliance with its written charter.

The Environmental, Safety and Security ("ESS") Committee

The ESS Committee reviews the Company's structure and operations to assess whether significant operating risks in the areas of environmental, safety and security have been identified and appropriate mitigation plans have been implemented. The ESS Committee also reviews the processes in place which are designed to ensure compliance with all environmental, safety and security related legal and regulatory requirements, as well as reviews with management the impact of proposed or enacted laws or regulations related to environmental, safety and security issues. Our ESS Committee held three meetings in 2006 and was in compliance with its written charter.

Compensation Committee Interlocks and Insider Participation

All members of the Compensation Committee during fiscal year 2006 were independent directors, and no member was an employee or former employee. No Compensation Committee member had any relationship requiring disclosure under "Transactions with Management and Others" on page 36. During fiscal year 2006, none of our executive officers served on the compensation committee (or its equivalent) or board of directors of another entity whose executive officer(s) served on our Compensation Committee.

Copies of Charters, Guidelines and Code of Ethics

A copy of the Audit, Compensation, Finance and Corporate Governance and Nominating Committee Charters, as well as our Corporate Governance Guidelines and Code of Ethics, are available on our Web site at www.UNS.com or may be obtained by shareholders, without charge, upon written request to Library and Resource Center, UniSource Energy Corporation, 3950 East Irvington Road, Mail Stop RC114, Tucson, Arizona 85714.

TRANSACTIONS WITH MANAGEMENT AND OTHERS

Related Person Transactions Policy

In February 2007, the Board adopted a written policy on the review of related person transactions (which is available on our website at www.UNS.com) that specifies that certain transactions involving directors, nominees, executive officers, significant shareholders and certain other related persons in which the Company is or will be a participant and are of the type required to be reported as a related person transaction under Item 404 of Regulation S-K shall be reviewed by the Audit Committee for the purpose of determining whether such transactions are in the best interest of the Company. The policy also establishes a requirement for directors, nominees and executive officers to report transactions involving a related party that exceeds $120,000 in value. We are not aware of any transactions entered into since adoption of the policy that did not follow the procedures outlined in the policy.

Melissa O'Brien

For 2007, the Company has engaged Melissa O'Brien, who is the daughter of the CEO, to provide regulatory consulting services to the Company and its subsidiaries primarily related to energy regulatory matters. During 2006, Ms. O'Brien was affiliated with the Wrona Law Firm of Park City, Utah ("Wrona"). In 2006, Wrona billed the Company for services in the amount of approximately $100,000, all of which was for work performed by Ms. O'Brien. Prior to her employment with the Wrona Law Firm, Ms. O'Brien was employed by the Troutman Sander Law Firm as a regulatory attorney; in this capacity she represented utility companies in rate proceedings. In February 2007, Ms. O'Brien terminated her affiliation with Wrona and entered into a consulting agreement with the Company to continue providing regulatory services. It is anticipated that billings for Ms. O'Brien's work in 2007 will exceed $100,000.

Haddington Energy Partners II LP

Millennium was authorized by its Board of Directors in 2000 to invest $15 million, in aggregate, over a three- to five-year period in Haddington Energy Partners II LP ("HEP II"). Mr. Bickle, a member of our Board, is a member and owns 30% of Haddington Ventures LLC, a private equity fund and the general partner of HEP II. Mr. Bickle also is a voting member of the investment committee that makes decisions with respect to Haddington Ventures investments. As of December 31, 2006, Millennium had invested $15 million under this commitment since its inception in exchange for approximately 31% ownership of the limited partner interest, and has received distributions of $15 million. Millennium continues to have an additional interest in two investments that have not been monetized. Millennium has no remaining funding commitment to Haddington. Millennium's total investment balance in Haddington at December 31, 2006 was $5 million. Mr. Bickle has advised the Board that the approximate dollar value of his interest in Millennium's investment is $313,000, contingent upon monetization of Millennium's remaining interest in HEP II.

AUDIT COMMITTEE REPORT

The Committee

The Audit Committee is made up of seven financially literate directors who are independent based upon independence criteria established by our Board, which criteria are in compliance with applicable NYSE listing standards. Our Board has determined that while each member of the Audit Committee has accounting and/or related financial management expertise, Mr. Handy is the Audit Committee financial expert for the purposes of Item 407(d)(5) of SEC Regulation S-K. In addition to Mr. Handy, there are four other financial experts on the Audit Committee. Each financial expert is independent as that term is used in Item 7(d)(3)(iv) of Schedule 14A under the Securities Exchange Act of 1934, as amended. The Board previously adopted a written charter for the Audit Committee. The Audit Committee Charter is included as Appendix A to this Proxy Statement. The Audit Committee has complied with its charter, including the requirement to meet periodically with our independent auditor, internal audit department and management to discuss the auditor's findings and other financial and accounting matters.

In connection with our December 31, 2006 financial statements, the Audit Committee has: (i) reviewed and discussed the audited financial statements with management, (ii) discussed with PricewaterhouseCoopers, LLP, our independent auditor, the matters required to be discussed by Statement on Auditing Standards No. 61, as amended (AIPCA, Professional Standards, Vol. 1 AU Sec. 380), as adopted by the Public Company Accounting Oversight Board in Rule 3200T, (iii) received from PricewaterhouseCoopers, LLP the written disclosures and the letter required by Independence Standards Board Standard No. 1 (Independence Standard Board Standard No. 1, Independence Discussions with Audit Committees), as adopted by the Company Accounting Oversight Board in Rule 3600T, and (iv) discussed with PricewaterhouseCoopers, LLP its independence.

Based on the review and discussions referred to in items (i) through (iv) of the above paragraph, the Audit Committee recommended to the Board that the audited financial statements for 2006 be included in the Annual Report on Form 10-K for filing with the SEC.

Pre-Approved Policies and Procedures

Rules adopted by the SEC in order to implement requirements of the Sarbanes-Oxley Act of 2002 require public company audit committees to pre-approve audit and non-audit services. Our Audit Committee has adopted a policy pursuant to which audit, audit-related, tax and other services are pre-approved by category of service. Recognizing that situations may arise where it is in our best interest for the auditor to perform services in addition to the annual audit of our financial statements, the policy sets forth guidelines and procedures with respect to approval of the four categories of service designed to achieve the continued independence of the auditor when it is retained to perform such services for us. The policy requires the Audit Committee to be informed of each service and does not include any delegation of the Audit Committee's responsibilities to management. The Audit Committee may delegate to the Chairman of the Audit Committee the authority to grant pre-approvals of audit and non-audit services requiring Audit Committee approval where the Audit Committee Chairman believes it is desirable to pre-approve such services prior to the next regularly scheduled Audit Committee meeting. The decisions of the Audit Committee Chairman to pre-approve any such services from one regularly scheduled Audit Committee meeting to the next shall be reported to the Audit Committee.

Fees

The following table details fees paid to PricewaterhouseCoopers, LLP for professional services during 2005 and 2006. The Audit Committee has considered whether the provision of services to us by PricewaterhouseCoopers, LLP, beyond those rendered in connection with their audit and review of our financial statements, is compatible with maintaining their independence as auditor.

	2005	2006
Audit Fees	$1,939,820	$1,677,681
Audit-Related Fees	$ 59,875	$ 45,000
Tax Fees	$ 40,465	$ 4,470
All Other Fees	$ 3,228	$ 3,243
Total	$1,840,813	$1,601,213

Audit fees include fees for the audit of our consolidated financial statements included in our Annual Report on Form 10-K and review of financial statements included in our Quarterly Reports on Form 10-Q. Audit fees also include services provided by PricewaterhouseCoopers, LLP in connection with the audit of the effectiveness of internal control over financial reporting and on management's assessment of the effectiveness of internal control over financial reporting, comfort letters, consents and other services related to SEC matters and financing transactions, statutory and regulatory audits, and accounting consultations to the extent necessary for PricewaterhouseCoopers, LLP to fulfill their responsibilities under generally accepted auditing standards.

Audit-related fees during 2006 principally include fees for employee benefit plan audits. During 2005, audit-related fees related primarily to fees for employee benefit plan audits and services related to extending the depreciable life of utility plants.

Tax fees include tax compliance, tax advice and tax planning.

All other fees consist of fees for all other services other than those reported above and, in 2005 and 2006, principally include subscription fees for research tools.

All services performed by PricewaterhouseCoopers, LLP are approved in advance by the Audit Committee in accordance with the Audit Committee's pre-approval policy for services provided by the independent auditor.

Respectfully submitted,

THE AUDIT COMMITTEE

Kenneth Handy, Chair
Warren Y. Jobe
Barbara M. Baumann
Harold W. Burlingame
John L. Carter
Robert A. Elliott
Joaquin Ruiz

SUBMISSION OF SHAREHOLDER PROPOSALS

General

Rule 14a-4 of the SEC's proxy rules allows us to use discretionary voting authority to vote on a matter coming before an annual meeting of our shareholders, which was not included in our Proxy Statement (if we do not have notice of the matter at least 45 days before the date on which we first mailed our proxy materials for the prior year's annual meeting of the shareholders).I n addition, we may also use discretionary voting authority if we receive timely notice of such matter (as described in the preceding sentence) and if, in the Proxy Statement, we describe the nature of such matter and how we intend to exercise our discretion to vote on it. Accordingly, for our 2008 annual meeting of shareholders, any such notice must be submitted to the Corporate Secretary of UniSource Energy, One South Church Avenue, Suite 1820, Tucson, Arizona, 85701, on or before February 17, 2008.

We must receive your shareholder proposals by December 4, 2007.

This requirement is separate and apart from the SEC's requirements that a shareholder must meet in order to have a shareholder proposal included in our Proxy Statement. Shareholder proposals intended to be presented at our 2008 annual meeting of the shareholders must be received by us no later than December 4, 2007 in order to be eligible for inclusion in our Proxy Statement and the form of proxy relating to that meeting. Direct any proposals, as well as related questions, to the undersigned.

DELIVERY OF PROXY MATERIALS TO HOUSEHOLDS

Only one copy of our 2006 Annual Report to Shareholders and Proxy Statement for the Meeting will be delivered to an address where two or more shareholders reside unless we have received contrary instructions from a shareholder at the address. A separate proxy card and a separate notice of the Meeting will be delivered to each shareholder at the shared address.

If you are a shareholder who lives at a shared address and you would like additional copies of the 2006 Annual Report, this Proxy Statement, or any future annual reports or proxy statements, please contact the Library and Resource Center, UniSource Energy Corporation, 3950 East Irvington Road, Mail Stop RC114, Tucson, Arizona 85714, telephone number (520) 745-3349, and we will promptly mail you copies.

If you share the same address with another UniSource Energy shareholder and you currently receive multiple copies of annual reports or proxy statements, you may request delivery of a single copy of future annual reports or proxy statements at any time by calling (520) 745-3349, or by writing to the Library and Resource Center, UniSource Energy Corporation, 3950 East Irvington Road, Mail Stop RC114, Tucson, Arizona 85714.

OTHER BUSINESS

The Board knows of no other matters for consideration at the Meeting. If any other business should properly arise, the persons appointed in the enclosed proxy have discretionary authority to vote in accordance with their best judgment.

Copies of our 2006 Annual Report on Form 10-K may be obtained by shareholders, without charge, upon written request to the Library and Resource Center, UniSource Energy Corporation, 3950 East Irvington Road, Mail Stop RC114, Tucson, Arizona 85714. You may also obtain our SEC filings through the Internet at www.sec.gov or www.UNS.com.

By order of the Board of Directors,

Linda H. Kennedy
Corporate Secretary

PLEASE VOTE - YOUR VOTE IS IMPORTANT

APPENDIX A

Amended
December 2, 2005

UNISOURCE ENERGY CORPORATION

AUDIT COMMITTEE OF THE BOARD OF DIRECTORS

CHARTER

1. **COMPOSITION**
The Audit Committee of the Board of Directors (the "Committee") consists of no fewer than three independent Directors appointed annually by the Board. Directors eligible to serve on the Committee shall be determined in accordance with the NYSE Listed Company Manual, Corporate Governance Standards for Audit Committees and the Sarbanes-Oxley Act of 2002. The Board shall designate one of the Committee members as Chairman of the Committee. Each member of the Committee shall be financially literate, and at least one member shall have accounting or financial management expertise.

2. **APPOINTMENT AND REMOVAL OF COMMITTEE MEMBERS**
All members of the Committee shall be appointed and/or removed by the Board of Directors.

3. **MEETINGS**
The Committee will hold at least four regular meetings each year, and such additional meetings as it may deem necessary. Additional meetings will be called by the Chairman of the Committee. The agendas for the regular meetings shall include all items necessary to complete the duties of the Committee as set forth herein. In addition to the Committee members and the Secretary, the Chairman of the Board, Chief Executive Officer and other members of management, internal audit and representatives of the independent auditor may attend as appropriate.

4. **RULES OF PROCEDURE**
The Committee will determine its own rules of procedure with respect to how its meetings are to be called, as well as the place and time.

5. **COMPENSATION**
Each member will be paid such fees as may be established from time to time by the Board for service on the Committee, and will be reimbursed for travel expenses incurred by attendance at meetings. Directors' fees are the only compensation an Audit Committee member may receive from the Company.

6. **COMMITTEE SECRETARY**
The Secretary of the Committee will be the Corporate Secretary of the Company (or such other representative of management as the Committee may designate) and not be a member of the Committee. The Secretary will attend all meetings and maintain minutes, advise members of all meetings called, arrange with the Chairman or other convening authority for preparation and distribution of the agenda for each meeting, and carry out other functions as may be assigned from time to time by the Committee. At such meetings where attendance by a Company representative is not appropriate, the Chairman shall act as secretary of the meeting or appoint another member of the Committee to act as secretary of such meetings.

7. **QUORUM**

A majority of the total membership of the Committee will constitute a quorum.

8. **COMMITTEE PURPOSE**

The Audit Committee is appointed by the Board to assist with Board oversight of

(1) the integrity of the Company's financial statements

(2) the Company's compliance with legal and regulatory requirements, except those handled by the Environmental, Safety & Security Committee

(3) the independent auditor's qualifications and independence, and,

(4) the performance of the Company's internal audit function and independent auditor.

The Audit Committee must also prepare the report that SEC rules require be included in the Company's annual proxy statement.

9. **SPECIFIC DUTIES OF THE COMMITTEE**

Independent Audit:

(1) Sole authority to appoint, retain and terminate the Company's independent auditor.

(2) Sole authority to approve all audit engagement fees and terms, as well as all significant, non-audit engagements (in accordance with SEC) with the independent auditor.

(3) Annually obtain and review a report from the independent auditor delineating all relationships between the auditor and the Company (to assess the auditor's independence).

(4) Review the experience and qualifications of the lead partner of the independent auditor.

(5) Ensure the rotation of the audit partner(s) as required by law.

(6) At least annually, obtain and review a report from the independent auditor describing the firm's internal quality control process, including any material issues raised by the most recent internal quality control review or peer review of the firm, or by any inquiry or investigation by governmental, regulatory or professional authorities within the past five years, respecting one or more independent audits carried out by the firm, and any steps taken to deal with any such issues.

(7) Review the results of each independent audit, including any qualifications in the independent auditor's opinion, and deficiencies identified by the independent auditor in connection with the audit.

(8) Review the annual audited financial statements with management and the independent auditor, including management's discussion and analysis, major issues regarding accounting and auditing principles and practices, as well as the adequacy of internal controls. Recommend to the Board, based on such review and discussion, whether the audited financial statements should be included in the Company's annual report on Form 10-K.

(9) Annually review an analysis prepared by management and the independent auditor of significant financial reporting issues, quality of financial reporting, and judgments made in connection with the preparation of the Company's financial statements, including an analysis of

the effect of alternative GAAP methods on the Company's financial statements. Review the procedures employed by the Company in preparing published financial statements and related management commentaries.

(10) Review with management and the independent auditor the Company's quarterly financial statements prior to the filing of its Form 10-Q, including management's discussion and analysis and the results of the independent auditor's review of the quarterly financial statements (SAS 90). Note: This can be performed by a member of the Audit Committee.

(11) Discuss annually with the independent auditor the required communications contained within Statement on Auditing Standards No. 61 relating to the conduct of the audit.

(12) Discuss with the independent auditor material issues on which the national office of the independent auditor was consulted by the Company's audit team.

(13) Meet with the independent auditor prior to the audit to discuss the planning and staffing of the audit.

Internal Audit:

(14) Review the appointment, replacement, reassignment or dismissal of the Company's General Auditor.

(15) Review and approve the internal audit department charter, annual audit plan and the audit methodology.

(16) Review management and General Auditor reports submitted to the Committee that are material to the Company as a whole, and management's response to those reports.

(17) Annually review the General Auditor's Summary of Officer's Annual Travel and Entertainment expense schedule. Include in this review a discussion of perquisites.

Miscellaneous:

(18) Review earnings press release as well as financial information and earnings guidance provided to analysts and ratings agencies.

(19) Review quarterly updates from management on material litigation.

(20) Periodically review with management and the Finance Committee, the Company's policies on major financial risk exposure, and the measures taken to reduce such risk.

(21) Annually review the Company's Corporate Code of Conduct and compliance therewith.

(22) Establish and maintain procedures for the confidential, anonymous submission by employees of the Company of concerns regarding accounting or auditing matters.

(23) Establish guidelines for the Company's hiring of employees or former employees of the independent auditor.

(24) Annually review this Audit Committee Charter and make any necessary changes.

(25) Annually perform an evaluation of the Committee, its members, functions and performance.

(26) Review disclosures made by the Company's CEO and CFO during their certification process for the Form 10-K and Form 10-Q about any significant deficiencies in the design or operation of internal controls or material weaknesses therein and any fraud involving management or other employees who have a significant role in the Company's internal controls.

10. EXECUTIVE SESSION

Meet quarterly with management, the General Auditor and the independent auditor in separate executive sessions.

11. RESPONSIBILITIES OF THE CHAIRMAN

The Chairman of the Committee will present the Committee's recommendations to the Board for its approval and periodically provide the Board, for its information, with a summary of the Committee's determinations and approvals. Additionally, set the annual compensation for the General Auditor in conjunction with the Company's Chief Executive Officer.

12. RESPONSIBILITIES OF THE CHIEF EXECUTIVE OFFICER

The Chief Executive Officer of the Company will advise and make recommendations to the Committee and, in the normal course, attend all meetings of the Committee.

13. OTHER AUTHORITY

The Audit Committee shall have the authority to retain special legal, accounting or other consultants to advise the Committee. The Audit Committee has full discretion to meet with individuals within or outside the Company.

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EXHIBIT
S-3
Admitted

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.26 Refer to Mr. Larson's rebuttal at page 3. If the cost of BMGS is more than $60 million:

a. What amount of cost would UNS Electric record on its books as plant in service as of June 1, 2008?

b. How would UNS Electric account for any difference between the actual cost of BMGS and the $60 million? Show illustrative journal entries, listing the amounts by account for all journal entries that UNS Electric would use.

c. What amount of cost for BMGS would UNS Electric begin depreciating on June 1, 2008?

d. If UNS Electric's proposal to include $60 million of BMGS in rate base as of June 1, 2008 were granted, would UNS Electric shareholders be responsible for depreciation on all plant costs over $60 million from June 1, 2008 until rates were reset for UNS Electric in a subsequent rate case in which the actual cost of the plant was addressed? Explain fully.

RESPONSE:

a. Upon the purchase of the BMGS from UniSource Energy Development Company ("UEDC"), the actual purchase price would be recorded as plant in service. Since the purchase price will be tied to the actual cost of completion, amount recorded as plant in service would reflect the cost of completion to UEDC.

b. So long as the Company is allowed to request rate base treatment of the full completion cost in a subsequent rate case, the full purchase price would be recorded as plant in service.

c. Consistent with the answer to part b. above, the Company would begin depreciating the full purchase price.

d. Yes. No cost deferrals are being requested for the period in between rate cases.

RESPONDENT: Kentton Grant

WITNESS: Kevin Larson

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S-4
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UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.27 Refer to Mr. Larson's rebuttal at page 4.

a. Please identify, quantify and explain the amount of "higher cash flows to the Company" that would come from customer rate increases. Please show this for each of the following periods (1) calendar 2008, (2) calendar 2009, (3) calendar 2010, (4) June 1, 2008 through May 31, 2009, and (5) June 1, 2009 through May 31, 2010. Provide the Company's best estimates. If the Company does not have any reliable estimates, please explain fully why not.

b. Please identify, quantify and explain the amount of cash flow increase to UNS Electric resulting from depreciation on BMGS. Please show this for each of the following periods (1) calendar 2008, (2) calendar 2009, (3) calendar 2010, (4) June 1, 2008 through May 31, 2009, and (5) June 1, 2009 through May 31, 2010. Provide the Company's best estimates. If the Company does not have any reliable estimates, please explain fully why not.

c. Please identify, quantify and explain the amount of cash flow increase that results from using accelerated tax depreciation related to BMGS for UNS Electric income tax filings. Please show this for each of the following periods (1) calendar 2008, (2) calendar 2009, (3) calendar 2010, (4) June 1, 2008 through May 31, 2009, and (5) June 1, 2009 through May 31, 2010. Provide the Company's best estimates. If the Company does not have any reliable estimates, please explain fully why not.

d. Provide all documentation from rating agencies that states that UNS Electric's credit profile would improve if its proposed ratemaking treatment for BMGS were permitted.

e. Please provide all correspondence between UNS Electric, its affiliates, and rating agencies relating to the Company's proposed ratemaking treatment for BMGS.

f. Do any rating agency reports address the Company's proposed ratemaking treatment for BMGS? If so, please identify and provide a copy of all such reports.

RESPONSE:

a. Please see STF 20.27 (a-c) on the enclosed CD.

b. Please see STF 20.27 (a-c) on the enclosed CD.

c. Please see STF 20.27 (a-c) on the enclosed CD.

d. UNS Electric is not rated by any of the major credit rating agencies, therefore no such documentation exists.

e. No such correspondence exists.

f. The rating agencies have not addressed BMGS.

The Excel file on the enclosed CD is not identified by Bates numbers.

RESPONDENTS: Kentton Grant (a)
Kevin Larson (b-f)

WITNESS: Kevin Larson

UNS Electric, Inc.
Cash Flow Effects of BMGS
Staff's 20th Set of Data Requests 20.27
-$ in Thousands-

STF 20.27 (A)

As described on page two of Mr. Larson's rebuttal testimony, UNS Electric, Inc. proposes a reclassification of rates effective June 1, 2008. With this rate reclassification, the Company would increase the average base delivery charge to customers by approximately 0.6 cents per kWh while simultaneously making a corresponding decrease of approximately 0.6 cents per kWh to the base power supply rate. The estimated pre-tax increase in cash flows to the Company resulting from the rate reclassification for each requested period is shown below.

$ in Thousands	2008	2009	2010	6/1/08-5/31/09	6/1/09-5/31/10
Retail Sales	896,700	1,923,420	2,023,301	1,843,005	1,958,249
Increase in Base Delivery Charge per kWh	0.006	0.006	0.006	0.006	0.006
Increase in Delivery Revenues	$5,000	$10,725	$11,282	$10,277	$10,919

UNS Electric, Inc.
Cash Flow Effects of BMGS
Staff's 20th Set of Data Requests 20.27
-$ in Thousands-

STF 20.27 (B)

As shown in Exhibit KPL-2, the forecasted annual depreciation expense on BMGS is approximately $1.5 million per year. The estimated pre-tax cash flow impact for each requested period is shown below. The amounts shown for 6/1/08-5/31/09 and 6/1/09-5/31/10 were calculated by extrapolating from the annual data provided in Exhibit KPL-2.

$ in Thousands	**2008**	**2009**	**2010**	**6/1/08-5/31/09**	**6/1/09-5/31/10**
Book Depreciation	$750	$1,502	$1,506	$1,376	$1,504

UNS Electric, Inc.
Cash Flow Effects of BMGS
Staff's 20th Set of Data Requests 20.27
-$ in Thousands-

STF 20.27 (C)

As shown in the Operating Cash Flow Impact section of Exhibit KPL-2, the deferred income taxes resulting from accelerated tax depreciation on BMGS would increase the Company's cash flows. The estimated cash flow increases that would result from accelerated tax depreciation related to BMGS are shown below for the periods requested. The amounts shown for 6/1/08-5/31/09 and 6/1/09-5/31/10 were calculated by extrapolating from the annual data provided in Exhibit KPL-2.

$ in Thousands

	2008	2009	2010	6/1/08-5/31/09	6/1/09-5/31/10
Book Depreciation	$750	$1,502	$1,506	$1,376	$1,504
Tax Depreciation	2,248	4,325	4,001	4,048	4,189
Net Impact on Taxable Income	(1,498)	(2,823)	(2,495)	(2,672)	(2,685)
Tax Rate	40%	40%	40%	40%	40%
Deferred Income Tax	$599	$1,129	$998	$1,069	$1,074

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UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.28 Refer to Mr. Larson's rebuttal at page 4, lines 24-25 and page 5, lines 1-2.

a. Please identify, quantify and explain the amount of additional debt needed to fund the purchase of BMGS under UNS Electric's proposal.

b. Please identify, quantify and explain the amount of additional debt needed to fund the purchase of BMGS under what Mr. Larson characterizes as "Staff's proposal."

c. Please identify, quantify and explain any and all differences in the amount of debt needed to fund the purchase of BMGS under UNS Electric's proposal and what Mr. Larson characterizes as "Staff's proposal."

RESPONSE:

a. As described on pages 14 through 15 of Mr. Larson's Direct Testimony, the Company is seeking authority to issue up to $40 million of new debt securities in order to fund the purchase of the BMGS. The Company's current financial forecast, which is summarized in Exhibit KCG-13 attached to the Rebuttal Testimony of Kentton Grant, assumes that UNS Electric will finance the purchase of the BMGS with $10 million of cash, $30 million of long-term debt and a $25 million equity contribution from UniSource Energy.

b. Due to the lower level of rate relief recommended by Staff, and the reliance on deferred accounting treatment for recovery of BMGS costs, it is unlikely that financing for the purchase of the BMGS would even be available under Staff's proposal. However, for illustration purposes, Exhibit KCG-13 attached to the Rebuttal Testimony of Kentton Grant assumes the same mix of financing for the BMGS purchase under both the Company's rate proposal and Staff's rate proposal.

c. Please see the response to part b.

RESPONDENT: Kentton Grant

WITNESSES: Kevin Larson and Kentton Grant

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UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.30 Refer to Mr. Larson's rebuttal at page 3, lines 1-3. Please explain fully Mr. Larson's understanding of the test year concept and why a test year is used.

RESPONSE: A test-year is necessary to provide a basis for Commission's review and reliance upon to establish just and reasonable rates. The test-year concept can be based on a historical test period of the Company, a historical test period adjusted for known changes or a forward-looking test-year.

RESPONDENT: Dallas Dukes

WITNESS: Kevin Larson

EXHIBIT
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UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.31 Refer to Mr. Larson's rebuttal at page 6, lines 13-14.

a. Please provide in detail UNS Electric's plans for refinancing the $60 million in long term debt that matures in August 2008. If the Company does not have any such plans, please explain fully why not.

b. If it were not for "the looming maturity of all $60 million of the Company's outstanding long-term debt in August 2008" would the Company's ratemaking proposal for BMGS be any different? If not, explain fully why not. If so, explain fully how it would be different.

RESPONSE:

a. The Company expects to refinance the $60 million of long-term debt in 2008 with the issuance of new debt in an amount of $100 million. Authority to issue up to $100 million of new debt was granted in Commission Decision No. 69395.

b. No. However, the Company's proposed treatment of BMGS allows UNS Electric to maintain and improve its financial position, which will allow it to enter the capital markets on more favorable terms. Deferred accounting treatment of BMGS would weaken UNS Electric's financial position and likely increase the cost of future financing activities.

RESPONDENT: Kevin Larson

WITNESS: Kevin Larson

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UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.32 Refer to Mr. Larson's rebuttal at page 6, lines 19-20: "There is no assurance, however, that UNS Electric's investment will be approved into rate base in a future proceeding." Please identify every factor that UNS Electric believes would cause its investment in BMGS not to be approved in rate base in a future proceeding in which BMGS was in service during the test year.

RESPONSE: The Company is concerned with Staff's position on the economics of UNS Electric owning BMGS. In Mr. Smith's Direct Testimony (page 89 at lines 10-12), he states, "[t]here is uncertainty regarding whether it would be economical for UNS Electric and its ratepayers for the utility to own the plant or obtain it by some other method." If the economics of owning BMGS are questioned in a future rate proceeding, there is a risk that the investment could be viewed as imprudent and not allowed to be in rate base. Additionally, there is a risk that a portion of the construction costs for the BMGS could be found imprudent and disallowed for ratemaking purposes. However, the Company believes that this risk is relatively small.

RESPONDENT: Kevin Larson

WITNESS: Kevin Larson

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UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.33 Refer to Mr. Larson's rebuttal at page 6, lines 21-22: "The Company cannot take the risk that BMGS could be found imprudent in UNS Electric's next rate case ..." Also refer to Mr. Larson's rebuttal at page 9, lines 8-9: "Additionally, the prudence of construction costs can be addressed in the Company's next rate case."

a. Please explain fully and in detail how the Company's proposed ratemaking for BMGS in the current case eliminates "the risk that BMGS could be found imprudent in UNS Electric's next rate case."

b. Admit that UNS Electric is seeking no determination or pre-determination of the prudence of the cost of BMGS in the current rate case. If this cannot be confirmed, explain fully why not.

c. Admit that the risk of an imprudent cost disallowance in UNS Electric's next rate case exists under the Company's proposed ratemaking proposal for BMGS, because the total cost of BMGS would not be reviewed in detail until the Company's next rate case. If this cannot be confirmed, explain fully why not.

d. Please explain fully the statement on page 12, lines 13-14, "UNS Electric is open to a full prudence review of those costs in the next rate case." Explain why this commitment by the Company does not present a risk that costs related to BMGS could be found imprudent in UNS Electric's next rate case.

RESPONSE:

a. If the Company's proposed rate treatment of BMGS is approved, the Commission would be making a determination that UNS Electric's ownership of BMGS is in the public interest. Regardless of the Commission's decision in this case, the Commission can review all costs of construction for the BMGS in a future rate proceeding. However, the Company believes that if its proposal is approved in this case, the risk of finding BMGS imprudent in a future case would be greatly diminished.

b. UNS Electric is seeking to make a rate reclassification based on the minimum expected cost of BMGS of $60 million. The Company will adjust the rate reclassification if the total costs are less than $60 million; UNS Electric will not seek to recover any costs in excess of $60 million until the next rate case.

c. The Commission has the right to review all costs in the context of a rate case. The Company anticipates that the costs of the BMGS will be reviewed in the Company's next rate case.

d. This statement merely reiterates that the Company recognizes the Commission's right to review all costs in a rate case proceeding. The Company fully realizes that there is no guarantee that all costs associated with BMGS will be found prudent in the next rate case.

RESPONDENT: Kevin Larson

WITNESS: Kevin Larson

EXHIBIT
S-10
Admitted

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.34 Refer to Mr. Larson's rebuttal at page 12, line 13: "UNS Electric has committed to acquiring BMGS at *cost* from UEDC."

a. Is this an enforceable and binding commitment? If not, explain fully why not. If so, who can enforce it and under what circumstances? Explain fully.

b. Please provide the documents in which this commitment has been made.

RESPONSE:

a. No. If the Company's rate proposal for BMGS is approved, a purchase agreement will be entered into between UNS Electric and UEDC, in which UNS Electric will purchase BMGS from UEDC at cost. The Company will provide a copy of this agreement to the Commission upon execution.

b. Not applicable.

RESPONDENT: Kevin Larson

WITNESS: Kevin Larson

EXHIBIT
S-11
Admitted

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.35 Refer to Mr. Larson's rebuttal at page 13, lines 3-4: "A short-term purchased power agreement would expose UNS Electric and its customers to refinancing risks."

a. Please identify, quantify and explain all such refinancing risks. If the risk is different to UNS Electric than it is to its customers, please provide separate quantifications and explain the differences. Please show this for each of the following periods (1) calendar 2008, (2) calendar 2009, (3) calendar 2010, (4) June 1, 2008 through May 31, 2009, and (5) June 1, 2009 through May 31, 2010. Provide the Company's best estimates. If the Company does not have any reliable estimates, please explain fully why not.

b. Please show and provide a copy of UNS Electric's specific plans for financing BMGS, the quantities of debt and equity anticipated, and the cost rates.

c. Has UNS Electric developed specific plans for financing BMGS? If not, explain fully why not.

RESPONSE:

a. Entering into a short or intermediate-term purchased power agreement for the output of BMGS until UNS Electric either purchases the facility or signs a long-term purchased power agreement means that the Company must wait for an indeterminate period time before it can lock in long-term financing. The long-term cost of the capacity from the BMGS would depend on the cost of capital obtained at some future point in time. If the Commission approves the Company's proposed rate treatment of the BMGS, long-term financing can be secured sooner rather than later, eliminating the refinancing risk. We cannot provide estimates that quantify such refinancing risks at this time.

b. Please see the response to STF 20.28. The cost of debt assumed in UNS Electric's financial forecast is 7.61%, which is the existing rate on UNS Electric's outstanding long-term debt.

c. Refer to the response to b. above.

RESPONDENT: Kevin Larson

WITNESS: Kevin Larson

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UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.36 Refer to Mr. Larson's rebuttal at page 7, line 6-7: "the Company would prefer to wait longer before filing another rate case."

a. Please quantify the period of time for delaying the next rate case filing if (1) the Company's proposed ratemaking treatment of BMGS were approved, and (2) the Company's proposed ratemaking treatment of BMGS were rejected.

b. Please state when the Company would file its next rate case under each of the following scenarios:

i. The Company's full amount of rate increase were granted, the Company's proposed ratemaking treatment of BMGS were approved, and the PPFAC proposed by Staff were approved.

ii. The amount of rate increase granted in the current case approximated the Staff's recommendation, the Company's proposed ratemaking treatment of BMGS were rejected, and the PPFAC proposed by Staff were approved.

RESPONSE: a. The quantifications are as follows:

(1) Assuming UNS Electric receives all or substantially all of the rate relief proposed in the Company's rate application, and further assuming that the proposed ratemaking treatment and purchase of the BMGS is approved, then UNS Electric estimates that another base rate increase would not be required for two to four years after new rates are implemented in this proceeding (i.e., filing in 2009 - 2011 for rates effective 2010 - 2012). However, the exact timing will depend on numerous factors including future changes in sales levels, operating expenses, plant investment and the Company's cost of capital.

(2) If the Company is provided with deferred accounting treatment for the BMGS instead of the proposed rate reclassification, and further assuming that financing is available to purchase the BMGS, the Company would likely file for another rate increase shortly after the BMGS enters commercial service (i.e., filing in 2008 for rates effective 2009).

b. Please see the following:

i. Assuming the PPFAC proposed by Staff does not result in significant cost disallowances or large deferral balances, the timing would be consistent with the response to part a.(1) above.

ii. The Company would likely file for another rate increase as soon as possible after receiving a final order in this proceeding.

RESPONDENT: Kentton Grant

WITNESSES: Kevin Larson and Kent Grant

EXHIBIT
S-13
Admitted

UNS ELECTRIC, INC.'S RESPONSES TO STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.37 Refer to Mr. Larson's rebuttal at page 8, lines 2-9. "if UEDC owns BMGS – UEDC could *immediately* begin to recover non-fuel costs by receiving *demand charges* under a wholesale purchased power agreement."

a. Has UEDC entered into negotiations to sell power from BMGS to any entities other than UNS Electric?

b. Based on the location of BMGS, what entities besides UNS Electric would have an interest in purchasing power generated at BMGS?

c. Does UEDC have specific plans to immediately being selling power from BMGS under a purchase power contract once the plant becomes commercially operational? If so, please describe such plans.

d. Mr. Larson's rebuttal at page 12, line 13, states that: "UNS Electric has committed to acquiring BMGS at cost from UEDC." If this doesn't occur on the time table proposed by UNS Electric, would UNS Electric try to obtain a purchased power contract with UEDC for power generated at BMGS? If not, explain fully why not. If so, please identify the anticipated timing of such a purchased power agreement.

RESPONSE:

a. No.

b. BMGS is located close on WAPA's system that has access to numerous market participants in Arizona, Nevada and even California. The proximity to the Mead trading hub makes BMGS attractive to utilities such as Nevada Power, Colorado River Commission and smaller municipalities in the area, as well as the large number of other market participants that transact at Mead. Mead is also a trading hub into California and utilities such as Southern California Edison, LADWP and San Diego Gas and Electric may also have an interest in its output. The plant is also situated well for Arizona utilities that interconnect to WAPA's transmission system, including Mohave Electric Power Cooperative, APS, SRP and TEP.

c. The Company has no specific plans at this point. However, if the purchase of the BMGS by UNS Electric cannot be completed, sales on the wholesale market would begin as soon as possible in order to provide cost recovery for the BMGS.

d. That is just one option being considered. The potential for higher overall costs to UNS Electric customers and the hurdles associated with such an affiliate transaction have already been discussed. If the Company pursued this option, it would target having a purchased power agreement in place before June 1, 2008.

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

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UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.51 Refer to Mr. Larson's rebuttal at page 8, lines 16-23: "by moving approximately $10 million out of the base power supply rate and into the Company's delivery charge, UNS Electric will have a reasonable opportunity to earn a return on this substantial investment. That is because the revenues produced by a power supply rate are reconcilable against fuel and purchased power cost, whereas the Company's delivery charges are not reconcilable and are retained for non-fuel cost recovery."

a. Please show in detail and quantify, by component, the additional cash flow in each year, June 1, 2008 for as far into the future as UNS Electric has projected it, resulting from moving approximately $10 million out of the base power supply rate and into the Company's delivery charge.

b. By reducing PPFAC (i.e., power supply rate) revenues by approximately $10 million per year for the shift out of the base power supply rate and into the Company's delivery charge, is the Company setting ratepayers up for PPFAC rate increases of approximately $10 million per year, commencing June 1, 2008 or at some later point? If not, explain fully why not.

c. How much PPFAC increase does UNS Electric anticipate for ratepayers starting June 1, 2008? Show the amounts of the PPFAC rate increase by component.

RESPONSE:

a. Please see the response to STF 20.27, part a.

b. No. The rate re-classification of BMGS will not "set up" customers for a PPFAC increase of $10 million. The amount of revenues collected from customers through the PPFAC reflects the actual cost of fuel, purchased power and transmission wheeling services purchased by UNS Electric to service its customers. The rationale for reducing the base power supply rate is that UNS Electric, by acquiring BMGS, will be able to avoid buying up to 90 MW of wholesale market capacity, ancillary services and transmission wheeling services.

c. The PPFAC rate will be initially reduced by $0.006 per kWh when the rate reclassification occurs. Any subsequent increases in the PPFAC will result from the actual cost of fuel, purchased power and transmission wheeling services purchased by UNS Electric to serve its customers.

RESPONDENT: Kevin Larson

WITNESS: Kevin Larson

EXHIBIT
S-15
Admitted

UNS ELECTRIC, INC.'S RESPONSES TO STAFF'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-06-0783 May 17, 2007

STF 3.61 AFUDC. Explain in detail the Company's procedure for accruing AFUDC, and provide examples of AFUDC accrued in the test year. Discuss specifically how the Company computes the AFUDC rate, computes AFUDC monthly, adjusts AFUDC for the impact of the Alternative Minimum Tax and for interest that is capitalized for federal income tax purposes. Show examples of each calculation.

RESPONSE: Consistent with R-14-2-212 G., of the Arizona Administrative Code ("AAC"), UNS Electric maintains its books and records in accordance with the Uniform System of Accounts ("USOA") of the Federal Energy Regulatory Commission ("FERC"). The computation of the AFDC rates and the accruals of AFDC are performed in accordance with Electric Plant Instruction No. 17 of the USOA. The AFDC rates computed in connection therewith are used on a gross-of-tax basis; thus, there are no Alternative Minimum Taxes or any other tax considerations. AFDC accruals are performed monthly, based on the average balance of Construction Work in Progress, for the respective month. The Company uses the same AFDC-Debt rate in capitalizing interest for both book and tax purposes. The only difference in the amounts of interest capitalized is attributable to differing book and tax bases for the respective assets.

Please see STF 3.61, Bates Nos. UNSE(0783)05047 to UNSE(0783)05048, on the enclosed CD for a copy of the current AFDC rate calculation and an example of the accrual of AFDC to an individual construction work order.

RESPONDENT: Carl Dabelstein

WITNESS: Karen Kissinger

UES (Gas and Electric rates)
AFUDC Calculation G:\Corpacct\Journal Entries & Source Documents\Recurring Journal Entries\2006\AFUDC and Capital Interest\[UES AFUDC-2006.xls]2006 Calc
2006 year

G:\Corpacct\Journal Entries & Source Documents\Recurring Journal Entries\2006\AFUDC and Capital Interest\[UES AFUDC-2006.xls]2006 Calc

Ai	gross allowance for borrowed funds used during construction rate
Ae	allowance for other funds used during construction rate
Ai	s(S/W) + d(D/(D + P + C)) (1 - S/W)
Ae	[1 - S/W][p(P/D + P + C) + c(C/(D + P + C))

		UNS Gas 2006		UNS Elec 2006	
S	short-term debt- average monthly balance	$ -		$ 11,309	5.2 B
s	short term debt interest rate	6.24%	5.1A	6.24%	5.2A
D	long-term debt	100,000	5.1B	60,000	5.2G
d	long-term debt interest rate	6.37%	PER BELOW	7.89%	PER BELOW
P	preferred stock	-		-	
p	preferred stock cost rate	-		-	
C	common equity at end of prior year	79,794	~~5.1C~~ 2B	49,881	~~5.2D~~ 2C
c	common equity cost rate per Rate Department	10.34%	3.1A	10.70%	4A
W	average monthly balance in CWIP	6,492	5.1D	15,315	5.2E
Ai =	gross allowance for borrowed funds used during construction rate	3.542920%	CALC. RY	5.734642%	CALC. RY
Ae =	allowance for other funds used during construction rate	4.588974%	CALC. RY	4.857316%	CALC. RY
Annual Rate		8.131894%	CALC RY	10.591957%	CALC RY
Monthly Rate		0.677658%	CALC. RY	0.882663%	CALC. RY

Interest on Long-Term Debt	$ 6,230,000	8 E	$ 4,566,000	8 F
Plus: Amortization of Debt Discount and Expense	139,958	6A	167,681	7A
Total Cost of Money	6,369,958	CALC RY	4,733,681	CALC. RY
Divided by Total Long-Term Debt	100,000,000	PER ABOVE	60,000,000	PER ABOVE
Weighted Long-Term Debt Cost Rate	6.37%	CALC RY	7.89%	CALC. RY

ACCOUNTING DEPARTMENT
Prepared by 2/3/06
Checked by 2/6/06
Approved by
Input by
Posted by

UNSE(0783)05047

SUBTOTALS- with Exp typ.dis
Sheet 1
03-MAY-07
03.54.47 PM
Service Type Code NOT LIKE 'Retirement', Segment1 = :Segment 1
Amount
Description, Amount, Creation Date, Expenditure Item Date, Expenditure Type
Segment 1: 330061A, Task: 8006790 Number

Task: 8006790	Project: 330061A	Description: Line Extensions < $50K King	Date Placed In Service: 07-DEC-2005

Description	Amount	Creation Date	Expenditure Item Date	Expenditure Type
VERNA SCHWAB, 6942 N. HORSE ME	① 94.40	02-MAY-2006	12-APR-2006	Materials Issued - UNE
VERNA SCHWAB, 6942 N. HORSE ME	1,514.05	02-MAY-2006	12-APR-2006	Materials Issued - UNE
VERNA SCHWAB, 6942 N. HORSE ME	257.35	04-MAY-2006	30-APR-2006	Stores Clearing
VERNA SCHWAB, 6942 N. HORSE ME	② * 8.12 4.40	05-MAY-2006	30-APR-2006	AFUDC - Debt UNSE
VERNA SCHWAB, 6942 N. HORSE ME	3.72	05-MAY-2006	30-APR-2006	AFUDC - Equity UNSE
VERNA SCHWAB, 6942 N. HORSE ME	③ 18.63	08-JUN-2006	31-MAY-2006	Allocated A&G - UNSE
VERNA SCHWAB, 6942 N. HORSE ME	753.57	08-JUN-2006	31-MAY-2006	Allocated E&S
VERNA SCHWAB, 6942 N. HORSE ME	30.00	08-JUN-2006	31-MAY-2006	Materials Issued
VERNA SCHWAB, 6942 N. HORSE ME	119.36	08-JUN-2006	31-MAY-2006	Allocated A&G
VERNA SCHWAB, 6942 N. HORSE ME	④ * 20.93 11.33	08-JUN-2006	31-MAY-2006	AFUDC - Debt UNSE
VERNA SCHWAB, 6942 N. HORSE ME	9.60	08-JUN-2006	31-MAY-2006	AFUDC - Equity UNSE
VERNA SCHWAB, 6942 N. HORSE ME	13.14	10-JUL-2006	30-JUN-2006	AFUDC - Debt UNSE
VERNA SCHWAB, 6942 N. HORSE ME	11.13	10-JUL-2006	30-JUN-2006	AFUDC - Equity UNSE

TOTAL: 2,840.68

APRIL CALC

Σ ① = 1865 80	APRIL EXPENSES
÷ 2	
932.90	AFUDC ELIGIBLE FOR APRIL
* 10 59156 %	RATE
* (30/365)	DAYS IN MONTH
② 8.12	TOTAL AFUDC FOR APRIL

MAY CALC

Σ ① = 1865.80	APRIL EXPENSE
Σ ③/2 460.78	MAY ⊥ (HALF OF MONTHLY EXPENSE)
2,326.58	AFUDC ELIGIBLE FOR MAY
* 10.59156 %	RATE
* (31/365)	DAYS IN MONTH
④ 20.93	TOTAL AFUDC FOR MAY

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UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007

STF 3.62 AFUDC.

a. Please identify all Customer Advances as of 6/30/05 and 6/30/06.

b. Please show in detail how Customer Advances are treated for purposes of computing AFUDC.

c. In what account(s) does the Company record Customer Advances?

d. Has the Company reflected Customer Advances as an offset to rate base on Schedule B-3, page 1, line 8? If so, explain fully why. If not, explain fully why not.

e. Does the Company agree that Customer Advances are not deducted from construction costs in computing AFUDC? If not, explain fully why not.

f. Please identify where in the Company's prefiled testimony, the rate base treatment of Customer Advances is addressed.

g. Does the Company agree that the Commission's rules require Customer Advances to be reflected as a reduction to rate base? If not, explain fully why not, and provide all authority upon which you are relying for your answer.

h. Is the Company and/or its affiliates aware of any public utility which has Customer Advances recorded on its books and which is regulated by the Arizona Corporation Commission that reflects the Customer Advances as a reduction to rate base? If so, please identify all such situations of which the Company and its affiliates are aware.

i. Is the Company and/or its affiliates aware of any public utility which has Construction Work in Progress recorded on its books and which is regulated by the Arizona Corporation Commission? If so, please identify all such situations of which the Company and its affiliates are aware.

j. Is the Company and/or its affiliates aware of any public utility which has Construction Work in Progress recorded on its books and which is regulated by the Arizona Corporation Commission and which has excluded the CWIP from rate base? If so, please identify all such situations of which the Company and its affiliates are aware.

k. Is the Company and/or its affiliates aware of any public utility which has both CWIP and Customer Advances recorded on its

books and which is regulated by the Arizona Corporation Commission? If so, please identify all such situations of which the Company and its affiliates are aware.

l. For each utility identified in response to part k, please explain fully the Company's understanding of the ratemaking treatment for CWIP and Customer advances. Please provide citations to any documentations you relied upon in preparing your response.

RESPONSE:

a. Please see STF 3.62 (a) on the enclosed CD for a listing of Customer Deposits as of the dates requested. The Excel file, STF 3.62 (a), is not identified by Bates numbers.

b. Customer Advances are not considered when computing AFUDC.

c. Customer Advances are recorded in FERC Acct. 252, Customer Advances for Construction.

d. Yes. The Company has included CWIP in rate base within its filing and thus, Customer Advances are deducted in total from rate base.

e. As stated in the response to part (b) above, Customer Advances are not considered in computing AFUDC accruals. In the previous rate case upon which current service rates are based, the balances of Customer Advances were deducted from rate base in their entirety. To also deduct them when computing AFUDC accruals would be tantamount to a double counting.

f. The rate base deduction for Customer Advances appears on Schedules B-1 (line 8), B-2, page 2 of 2 (line 8) and B-3, page 2 of 2 (line 8). Company witness Ms. Kissinger sponsors Schedules B-1 through B-5 on pages 16 through 20 of her Direct Testimony. The rate base deduction for Customer Advances is specifically addressed at line 19 of page 16.

g. The Company is aware of no Commission rule that specifically identifies that 100% of Customer Advances be deducted in arriving at total original cost rate base. Arizona Administrative Code R14-103h, defines original cost rate base as follows, "Original cost rate base – An amount consisting of the depreciated original cost, prudently invested, of the property (exclusive of contributions

and/or advances in aid of construction) at the end of the test year, used or useful, plus a proper allowance for working capital and including all applicable pro forma adjustments." This definition of original cost rate base doesn't specifically identify if advances invested into property not yet found used and useful by the Commission should be deducted from rate base. It is the Company's position that to do so denies them an opportunity to earn a reasonable return on a portion of their prudently invested rate base used and useful at the end of the test year.

h. Yes. The Company is aware that at least some portion of Customer Advances were reflected as a reduction of rate base in the most recent filings of UNS Gas, Southwest Gas, Arizona Public Service Company and in the previous rate cases upon which current service rates are based for UNS Gas and Electric. It is likely that most rate cases filed with the Commission reflected at least some portion of Customer Advances as a reduction of rate base if the filing Company had a Customer Advance balance at test year end.

i. Arizona Administrative Code R14-212-G and R14-G require electric and gas utilities regulated by the ACC to maintain their books and records in accordance with the USOA of the FERC. The USOA requires a proper accounting distinction between Construction Work in Progress (Acct. No. 107) and Plant in Service (Acct. 101). We are not aware of any gas or electric company regulated by the ACC that is not complying with such requirements.

j. To the best of our knowledge, CWIP has been excluded from rate base in previous TEP rate cases and also in the most recent rate cases involving Citizens former Arizona properties, the assets of which now comprise UNS Gas and UNS Electric.

k. We are not aware of any Arizona utility that did not have CWIP and Customer Advances on its books.

l. We are aware of two instances where CWIP was included in rate base and one instance where less than 100% of the Customer Advance balance at the end of the test year was reflected as a reduction of rate base. One was an APS rate case in the early

1980's in which the ACC permitted the inclusion of $450 million Palo Verde CWIP in rate base to avoid financial hardship. The other was a 1985 Mountain Bell rate case in which, consistent with the then Uniform System of Accounts of the Federal Communications Commission, $16 million of short-term CWIP (construction projects with an expected duration of less than one year) was included in rate base. The Customer Advances amount used to reduce rate base in the 2005 Southwest Gas rate case was less than the actual test year ended amount.

RESPONDENT: Dallas Dukes and Kent Grant

WITNESS: Karen Kissinger and Kent Grant

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STF 20.11 Refer to Mr. DeConcini's rebuttal at page 4, line 5: "Most importantly, UEDC is developing BMGS specifically for the needs of UNS Electric."

a. Is there any contract between UNS Electric and UEDC related to the development of BMGS? If so, please provide a copy.

b. When UEDC began developing BMGS was any understanding or representation made to UEDC that UNS Electric would buy the plant at cost from UEDC? If so, please provide the document(s) or other source for such understanding or representation. If not, explain fully why not.

RESPONSE:

a. No, there is no contract between UNS Electric and UEDC. UniSource Energy Corporation ("UniSource Energy") is utilizing UEDC to manage and develop BMGS for UNS Electric.

b. Yes, UEDC and UNS Electric understood from the start that UEDC would develop BMGS and transfer it to UNS Electric at cost. This understanding has been annotated in UniSource Energy's 2006 Form 10K filing (p. 34).

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

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STF 20.12 Refer to Mr. DeConcini's rebuttal at page 5, lines 4-8.

a. Has UNS Electric held a competitive RFP? If not, explain fully why not.

b. What is the source for the FERC requirement? Provide the document relied upon for such FERC requirement.

c. Is the referenced FERC requirement intended to provide a safeguard? If so, please explain fully your understanding of the safeguard. If not, explain fully why not.

d. Is the Company's proposed ratemaking treatment of BMGS in the current rate case a way to bypass having to obtain FERC approval?

RESPONSE:

a. UNS Electric has performed numerous competitive RFP's over the past three years, but received few proposals specifically for dispatchable peaking capacity even though it was one of the requested products. UNS Electric currently has a competitive RFP in process, at this time being administered by an Independent Monitor specifically requesting peaking capacity for delivery into its Mohave County load area. Bids are to be received September 6, 2007.

b. FERC prohibits market-based rates sales between a regulated utility and its unregulated affiliate without specific approval through a Federal Power Act Section 205 filing. This prohibition can be found in FERC's recent Order 697, paragraph 467. See STF 20.12 (b) (Order 697), Bates Nos. UNSE(0783)10953 to UNSE(0783)11607, on the enclosed CD for a copy of FERC Order 697. FERC has granted approvals for these types of affiliate sales as long as certain conditions are met, including holding a competitive RFP meeting the "Allegheny criteria," see Order 697 paragraph 532 and footnote 544 and paragraph 540. Please see STF 20.12 (b) (Allegheny), Bates Nos. UNSE(0783)10941 to UNSE(0783)10952, on the enclosed CD for a copy of entire Allegheny Order.

c. Yes. The requirement is to provide a safeguard or protection from the ability of an unregulated entity to charge unchecked market based rates to a regulated affiliate.

d. Absolutely not. The Company is not requesting to make a market-based rate sale between UEDC and UNS Electric. It is not requesting to make a power sale of any kind. Rather the Company

is asking to transfer BMGS to UNS Electric and for a post test year adjustment to bring BMGS into UNS Electric's rates at cost on June 1, 2008 since UEDC is simply developing BMGS for UNS Electric.

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

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STF 20.14 Refer to Mr. DeConcini's rebuttal at page 6, lines 7-9.

a. Please quantify the "risk of an unknown market-based capacity charge." If the risk is different to customers than it is to the Company, please quantify the risk to each.

b. If you cannot quantify such risk, explain fully why not.

RESPONSE:

a. This risk of a market-based capacity charge is that it is unknown and therefore cannot be quantified. Market-based capacity charges can be determined through competitive RFP's for the defined RFP period. In the case of short-term PPA's, the risk remains for the period beyond the initial PPA term. The Company and its customers' risks, while related, are different. The Company's risk is timely recovery of capacity costs and its effect on its cash flow, borrowing costs and credit requirements. The customers' risk is ultimately higher rates due to short-term capacity cost increases and the higher costs of borrowing and credit.

b. See the response to a. above.

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

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UNS ELECTRIC, INC.'S RESPONSES TO
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STF 20.15 Refer to Mr. DeConcini's rebuttal at page 7, lines 13-18.

a. Please confirm that the Company can provide no assurance that its proposed ratemaking treatment of BMGS will save ratepayers money in any year, 2008, 2009 or 2010. If this cannot be confirmed, please identify, quantify and explain the annual revenue requirement savings that the Company is assuring will inure to ratepayers in each year.

b. Please confirm that the Company could seek an accounting order for BMGS that, if granted, would provide for deferred cost accounting and potential future recovery of deferred costs. If this cannot be confirmed, explain fully why not.

c. If its proposed ratemaking treatment for BMGS is rejected in the current case, has Company management totally ruled out ever seeking an accounting order for BMGS? If so, please provide a clear statement to this effect.

d. Please confirm that the Company could include BMGS in rate base in a future rate case. If this cannot be confirmed, explain fully why not.

e. If its proposed ratemaking treatment for BMGS is rejected in the current case, has Company management totally ruled out ever seeking inclusion of BMGS in rate base in a future case? If so, please provide a clear statement to this effect.

f. Please confirm that the Company could hold a competitive RFP (per DeConcini rebuttal page 5, lines 4-8) to assure that purchasing power from the BMGS unit is the least cost (lowest bid) option. If this cannot be confirmed, explain fully why not.

g. Please confirm that the Company could hold a competitive RFP (per DeConcini rebuttal page 5, lines 4-8) to assure that purchasing power from the BMGS unit is the least cost (lowest bid) option, but management would prefer not to have to do this. If this cannot be confirmed, explain fully why not.

h. Please confirm that the Company does not know with any degree of precision and cannot quantify the annual revenue requirement reductions that would inure to ratepayers in any year, 2008 through 2010, from its proposed ratemaking treatment of BMGS. If this cannot be confirmed, please identify, quantify and explain the

annual revenue requirement savings that the Company's proposal will provide to ratepayers in each year.

i. Please confirm that the Company's proposed ratemaking treatment of BMGS could result in a higher total revenue requirement and higher rates (considering both base rates and PPFAC rates) to its customers in future years starting June 1, 2008, than if some other option were used. If this cannot be confirmed, please explain fully and elaborate upon how the Company will assure that ratepayers rates under its BMGS proposal are no higher than they would be under any other options.

RESPONSE:

a. The Company can, and has, provided its estimate of savings that BMGS will provide to its customers based on previous RFP bids as described in the Direct Testimony of Mr. Michael DeConcini and Mr. Kevin Larson. The Company will provide specific confirmation to savings in the referenced years upon the conclusion of its current RFP.

b. Yes, the Company could seek an accounting order for BMGS that, if granted, would provide deferred cost accounting and potential future recovery of deferred costs. However, the issues with an accounting order have been fully explained in Mr. Kevin Larson's Rebuttal Testimony.

c. If its proposed ratemaking treatment for BMGS is rejected in the current case, the Company has not totally ruled out ever seeking an accounting order for BMGS.

d. Yes, the Company could include BMGS in rate base in a future rate case. The Company has fully explained the problems with this approach.

e. No.

f. The Company could hold a competitive RFP to assure that purchasing power from the BMGS unit is the least cost (lowest bid) option. This RFP is currently in process.

g. The Company is currently holding a competitive RFP for that purpose.

h. The Company does know with a reasonable degree of precision and can estimate the annual revenue requirement reductions that would inure to ratepayers in any year, 2008 through 2010, from its

proposed ratemaking treatment of BMGS. Also, see the response to a. above.

i. There is no way to refute such a confirmation. There are many options, even ones that don't exist today, that could turn out to have a lower total revenue requirement and lower rates than BMGS under the right set of circumstances using a hindsight review. Both gas and power markets are subject to volatility and influence from many factors beyond our control including economic, social and political changes. This in no way affects the decision that has to be made today with today's facts and circumstances. At this time the Company believes it is the lowest cost long-term option.

RESPONDENT: Michael DeConcini

WITNESS: Michael DeConcini

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STF 20.6 Refer to Exhibit MJD-3, the UNS Electric, Inc. Purchased Power and Fuel Adjustment Clause Plan of Administration filed with Mr. DeConcini's rebuttal testimony. For each item of "Other Allowable Costs" on page 11, explain fully why base rate recognition of prudent and normalized levels of such costs would be inadequate.

RESPONSE: The Company's purpose is to recover these costs as they are incurred in the future. Some components are easily estimated, others are not. The Company believes including these costs in the PPFAC is a more efficient mechanism and a better match between actual cost and recovery. However, if these costs are excluded from the PPFAC mechanism, a normalized adjustment to the base rates filed in this case would be necessary to recover these costs.

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

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STF 20.7 Refer to Exhibit MJD-3, the UNS Electric, Inc. Purchased Power and Fuel Adjustment Clause Plan of Administration filed with Mr. DeConcini's rebuttal testimony. Refer to the items of "Other Allowable Costs" on page 11, if the Company were forced to choose between (1) no PPFAC and (2) a PPFAC that included all of the other provisions in Exhibit MJD-3 except the provision for "Other Allowable Costs," which option would the Company choose and why?

RESPONSE: If forced to choose between only those two options, the Company would choose to have a PPFAC that included all of the other provisions in Exhibit MJD-3, except the provision for "Other Allowable Costs." This would be chosen since the risk and variability of the other fuel and purchase power costs are expected to exceed that associated with the "Other Allowable Costs." That being said, the Other Allowable Costs still contain risk and variability and are not recovered in existing base rates as previously explained.

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

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STF 20.8 Refer to Exhibit MJD-3, the UNS Electric, Inc. Purchased Power and Fuel Adjustment Clause Plan of Administration filed with Mr. DeConcini's rebuttal testimony. The Company proposes that: "the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PPFAC." Provide the following information regarding hedging costs:

a. A listing, by account, by calendar year (or portion of calendar years 2003 through 2007), of the actual hedging costs incurred by UNS Electric from the inception of ownership of UNS Electric in August 2003 through June 30, 2007.

b. A listing, by account of the anticipated, estimated, and/or forecast expenses incurred by UNS Electric for hedging for each of the following periods: (1) calendar 2007, (2) calendar 2008, (3) calendar 2009, (4) calendar 2010, (5) June 1, 2008 through May 31, 2009, and (6) June 1, 2009 through May 31, 2010. Provide the Company's best estimates. To the extent that the requested estimated or forecast information is not available in exactly the form requested (by FERC account), provide the best information the Company has and in the form that the Company has it in.

RESPONSE:

a. The Company has not incurred any of these costs since inception of ownership due to the fixed price, full requirements contract with Pinnacle West.

b. Forward gas and purchased power contracts are expensed through FERC Accounts 501, 547 and 555 in the month of delivery. To date, UNS Electric has entered into purchased power contracts which will be expensed through FERC Account 555 in the month of delivery and are broken down into the requested format which is provided as STF 20.8 on the enclosed CD. Gas indexed power contract prices are estimated using forward gas prices as of July 31, 2007. The Excel file on the enclosed CD is not identified by Bates numbers.

Hedging costs also include instruments such as financial swaps that the Company uses to fix, or hedge, portions of its expected natural gas consumption and fix the price of gas-indexed power contracts. These swaps financially settle at the difference between the fixed price that the Company purchases and the spot market prices. This financial settlement, combined with the Company's

physical spot market purchases, nets to the fixed hedge price. The financial settlement of these hedges are charged or credited to FERC Account 547 or 501 for natural gas or FERC Account 555 for Purchased Power for the applicable month. Since these types of hedges are settled based on the difference between a fixed price and actual spot market indices, it is not possible to forecast these charges and credits for hedges that have not yet been executed, as the fixed price and expected spot price would be the same on a forecast basis. However, the hedges currently in place can be valued on a mark-to-market basis with forward prices to estimate the future charge/credit. STF 20.8 delineates the requested information for existing swap hedges.

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

Hedged Month	Hedged Baseload Total	Average Purchase Price	Current Price	Mark to Market
Jun-08	158,700	$ 7.591	$ 7.15	$ (69,301.50)
Jul-08	168,600	$ 7.806	$ 7.38	$ (71,454.90)
Aug-08	148,800	$ 7.874	$ 7.49	$ (57,848.80)
Sep-08	118,200	$ 7.916	$ 7.45	$ (55,094.50)
Oct-08	94,400	$ 7.864	$ 7.30	$ (53,519.20)
Nov-08	92,800	$ 8.265	$ 7.91	$ (33,187.00)
Dec-08	102,700	$ 8.738	$ 8.38	$ (37,066.10)
2008 Total				**$ (377,472.00)**
Jan-09	85,100	$ 8.999	$ 8.64	$ (30,774.60)
Feb-09	72,200	$ 8.991	$ 8.66	$ (24,110.00)
Mar-09	73,900	$ 8.738	$ 8.44	$ (22,250.10)
Apr-09	69,200	$ 7.578	$ 7.35	$ (15,975.00)
May-09	81,300	$ 7.459	$ 7.33	$ (10,299.80)
Jun-09	86,700	$ 7.537	$ 7.42	$ (9,791.60)
Jul-09	93,800	$ 7.623	$ 7.68	$ 5,061.00
Aug-09	88,400	$ 7.684	$ 7.74	$ 4,665.60
Sep-09	72,100	$ 7.730	$ 7.72	$ (937.80)
Oct-09	58,600	$ 7.827	$ 7.64	$ (11,279.00)
Nov-09	57,800	$ 8.156	$ 8.04	$ (6,733.10)
Dec-09	60,700	$ 8.575	$ 8.36	$ (13,028.90)
2009 Total				**$ (135,453.30)**
Jan-10	53,500	$ 8.844	$ 8.47	$ (20,266.60)
Feb-10	47,900	$ 8.833	$ 8.49	$ (16,516.31)
Mar-10	51,300	$ 8.578	$ 8.21	$ (18,705.00)
Apr-10	48,200	$ 7.312	$ 7.12	$ (9,122.00)
May-10	56,300	$ 7.187	$ 7.09	$ (5,380.60)
Jun-10	53,000	$ 7.255	$ 7.21	$ (2,182.60)
Jul-10	59,700	$ 7.339	$ 7.45	$ 6,639.90
Aug-10	27,700	$ 7.459	$ 7.53	$ 1,862.80
Sep-10	12,200	$ 7.420	$ 7.49	$ 817.40
2010 Total				**$ (62,853.01)**

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STF 20.16 Refer to Mr. DeConcini's rebuttal at page 8, lines 12-13. Also, refer to Exhibit MJD-3.

a. Please explain fully why "UNS Electric believes that Staff's proposed mechanism for APS will be effective in mitigating the volatility in its power supply and delivery costs."

b. Is UNS Electric aware of any substantial differences in Staff's proposed mechanism for APS and the PPFAC mechanism proposed in UNS Electric's rebuttal testimony? If so, please identify all such differences which UNS Electric believes are significant.

RESPONSE:

a. By using a forward looking, 12-month mechanism, customers will not be subject to monthly variations in pricing. The intra-year variations are smoothed out and turned into a once per year adjustment.

b. There are a few differences between APS' PSA and UNS Electric's proposed PPFAC:

1. UNS Electric does not propose a sharing mechanism. There are substantial differences in the relationship between base rates and PPFAC rates since APS' base rate was based on a static asset-based system and UNS Electric's base rate is being set on a full requirements contract that will expire before the PPFAC rate will take effect.

2. UNS Electric does not propose a cap on the PPFAC rate change. The reason for this is also related to the base rate difference as well as UNS Electric's asset base vis-à-vis APS'.

3. UNS Electric has included some additional allowable costs in its PPFAC due to its unique circumstance of converting from a full-requirements contract and not having certain of the necessary costs of such a conversion in base rates (Energy Procurement, Credit costs, Legal expenses, Future Interconnection costs).

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

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STF 20.17 Refer to Mr. DeConcini's rebuttal at page 11, lines 12-13: "costs are based on forecasts that accurately reflect what fuel and energy costs are anticipated to be." Please provide the documentation relied upon for assuming that the Company's forecasts would accurately reflect what fuel and energy costs the Company will actually incur in the following year.

RESPONSE: Mr. DeConcini states that "costs are based on forecasts that accurately reflect what fuel and energy costs are anticipated to be." This anticipation relies upon the fact the Company would use the most recent load and resource estimates, existing forward purchases and hedges, and forward gas and power prices. These will all be the best estimates at a specific point in time. The load forecast and the non-hedged forward gas and power prices are estimates and actual costs incurred will vary from the forecast. The PPFAC mechanism takes this into account with the true-up rate the following year.

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

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STF 20.19 Refer to Mr. DeConcini's rebuttal at page 15-16 concerning a sharing mechanism in the PPFAC.

a. If the Commission included a sharing mechanism in UNS Electric's PPFAC similar to the mechanism in the APS PSA, would that in any way impact UNS Electric's forecasts of fuel and purchased power cost? If not, explain fully why not. If so, please identify, quantify and explain the impact.

b. If the Commission included a sharing mechanism in UNS Electric's PPFAC similar to the mechanism in the APS PSA, would that in any way impact UNS Electric's hedging strategy for fuel and purchased power cost? If not, explain fully why not. If so, please identify, quantify and explain the impact.

RESPONSE:

a. Possibly. These costs are solely based on loads, resources and energy price forecasts. Credit concerns arising from a sharing mechanism could increase energy price forecasts.

b. No. A sharing mechanism would not impact UNS Electric's fuel and purchased power hedging strategy. The Company's hedging strategy is designed to stabilize rates for our customers through mechanistic forward hedges and a sharing mechanism would not affect this policy. However, credit concerns associated with a sharing mechanism could make execution of the strategy more difficult or expensive.

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

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STF 20.20 Refer to Mr. DeConcini's rebuttal at page 14 concerning caps and restrictions on the PPFAC.

a. If the Commission included caps or restrictions in UNS Electric's PPFAC similar to the mechanism in the APS PSAM, would that in any way impact UNS Electric's forecasts of fuel and purchased power cost? If not, explain fully why not. If so, please identify, quantify and explain the impact.

b. If the Commission included caps or restrictions in UNS Electric's PPFAC similar to the mechanism in the APS PSAM, would that in any way impact UNS Electric's hedging strategy for fuel and purchased power cost? If not, explain fully why not. If so, please identify, quantify and explain the impact.

RESPONSE:

a. Possibly. These costs are solely based on loads, resources and energy price forecasts. Credit concerns arising from a cap could increase energy price forecasts.

b. No. A cap would not impact UNS Electric's fuel and purchased power hedging strategy. The Company's hedging strategy is designed to stabilize rates for our customers through mechanistic forward hedges and a cap would not affect this policy. However, credit concerns associated with a cap could make execution of the strategy more difficult or expensive.

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

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STF 20.21 Refer to Mr. DeConcini's rebuttal at page 16, lines 19-21. Please show in detail, by account, how the Company would account for off-system sales revenues and costs.

RESPONSE: All fuel and purchased power costs associated with off-system wholesale sales are charged to FERC Accounts 501, 547 and 555, as appropriate, and flow into the PPFAC bank. The Company would credit all short-term wholesale sales revenue from FERC Account 447 to the PPFAC bank. Although the Company does not currently have any long-term wholesale sales that are jurisdictionally allocated out of rates, if the Company does have any of these sales in the future, the associated fuel and purchased power costs will be removed from the PPFAC at average cost per normal jurisdictional allocation process.

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

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STF 20.2 Refer to Exhibit MJD-3, the UNS Electric, Inc. Purchased Power and Fuel Adjustment Clause Plan of Administration filed with Mr. DeConcini's rebuttal testimony.

a. How much of a True-Up component based on the period June 1, 2008 through May 31, 2009, does the Company estimate if its proposed ratemaking treatment for BMGS is adopted in the current case? Provide the Company's best estimates. If no estimates are available, explain fully why not.

b. How much of a True-Up component based on the period June 1, 2008 through May 31, 2009, does the Company estimate if its proposed ratemaking treatment for BMGS is NOT adopted in the current case? Provide the Company's best estimates. If no estimates are available, explain fully why not.

c. Please explain any substantial differences between the results identified in response to parts a and b, above.

RESPONSE: a.-c. Since the True-Up Component reconciles any over- or under-recovered amounts from the preceding PPFAC year, and June 1, 2008 through May 31, 2009 is for a forecast period, the True-Up Component is zero, regardless of whether the Company's proposed ratemaking treatment for BMGS is or is not adopted. Please also see the response to STF 20.3.

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

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STF 20.18 Refer to Mr. DeConcini's rebuttal at page 15, lines 1-9.

a. Please state fully your understanding of whether any of those other costs are allowed to be included in the APS PSAM.

b. Please identify the account(s) in which UNS Electric would record each type of cost.

c. When does the Company anticipate that it would begin incurring each type of cost? Explain fully.

d. Does the Company expect that such costs will be material and volatile? If not explain fully why not. If so, provide all information relied upon for such expectations.

e. Are any other electric or gas utilities in the State of Arizona allowed to include brokers fees in their PPFAC or PGA? If so, which ones?

f. Are any other electric or gas utilities in the State of Arizona allowed to include credit costs in their PPFAC or PGA? If so, which ones?

g. Are any other electric or gas utilities in the State of Arizona allowed to include legal fees in their PPFAC or PGA? If so, which ones?

h. Please provide any documents relied upon for your answers to parts a through g.

RESPONSE:

a. It is UNS Electric's understand that broker fees are included in APS' base rates as describe in Decision No. 69663 and APS' final POA for its PSA. The Company also understands that APS' credit costs and legal fees are recovered through its base rates, whereas UNS Electric has no such costs in its base rate request.

b. Broker fees would be recorded in Account 557 (same as APS). Legal fees and credit costs would continue to be recorded in FERC Accounts 923 and 431, respectively. These costs would be a line item addition to the PPFAC with all appropriate documentation.

c. Broker fees would be incurred starting in June, 2008. UNS Electric cannot anticipate the timing of legal or credit costs with any certainty.

d. Yes. UNS Electric expects these costs to be both volatile and material. The Company expects the legal and credit cost to be

intermittent and related to specific events, transactions or circumstances based on our experience at the Company's affiliates.

e. Yes, it is UNS Electric's understanding that APS has brokers fees included in its base rates.

f. UNS Electric is not aware of any other electric or gas utilities in the State of Arizona allowed to include credit costs in its PPFAC or PGA, although some credit costs could be imbedded into the energy costs passed through a PPFAC or PGA mechanism.

g. UNS Electric is not aware of any other electric or gas utilities in the State of Arizona allowed to include legal fees in their PPFAC or PGA.

h. Only the APS' PSA POA and Decision No. 69663 were relied upon for these responses.

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

ARIZONA CORPORATION COMMISSION'S RESPONSE TO
UNS ELECTRIC, INC.
FIRST SET OF DATA REQUESTS TO STAFF
DOCKET NO. E-04204A-06-0783
August 1, 2007

EXHIBIT
S-33
Admitted
ALL-STATE LEGAL®

1.31 **Please provide a copy of the Arkansas Public Service Commission's Order No. 10 in Docket No. 06-101-U (June 15, 2007). Did Mr. Smith rely on any other public utility commission decisions with regards to his C-12 adjustment? If so, please provide a copy of those decisions or the docket number, order number, jurisdiction and caption of those decisions.**

RESPONSE: See Attachment UNSE 1.31 for a copy of that decision.

Not specifically; however, based on his experience, in general, it is fairly typical for non-tax deductible expenditures related to lobbying and attempting to influence legislation to be disallowed. Also, in general, the purpose of the NARUC-designated categorization of EEI expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. As described in prior NARUC-sponsored audits of EEI expenditures, often state commissioners review the costs of the utility industry association that are charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities. Certain expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit. The NARUC-designated categories of EEI expenditures are thus intended to be helpful to state utility regulatory commissions. Based on his experience, Mr. Smith understands that there may be numerous other public utility commission decisions in which some use of the NARUC-designated categories of EEI expenditures were utilized; however, he has not attempted to compile a listing of such decisions and does not have such a list. To attempt to compile such a listing would be extremely burdensome and could involve several hours or days of additional research.

RESPONDENT: Ralph Smith

WITNESS: Ralph Smith

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JUN 15 4 16 PM '07

ARKANSAS PUBLIC SERVICE COMMISSION

FILED

IN THE MATTER OF THE APPLICATION OF)
ENTERGY ARKANSAS, INC. FOR APPROVAL)
OF CHANGES IN RATES FOR RETAIL)
ELECTRIC SERVICE)

DOCKET NO. 06-101-U
ORDER NO. 10

EXHIBIT
IS-34
Admitted

ORDER

Summary

On August 15, 2006, Entergy Arkansas, Inc. ("EAI") filed in this Docket its Application seeking an increase in the rates it charges its Arkansas retail electric customers. As later amended, EAI seeks a retail revenue requirement increase of $106,534,000 or approximately 11.79% above its current authorized retail revenue requirement. However, based upon the evidence presented in this Docket, the Commission finds that EAI's retail revenue requirement is excessive and should be reduced by approximately $5.67 million effective as of June 15, 2007. Among other adjustments the Commission denied EAI's request for an 11.25% return on equity. Instead, the Commission set EAI's return on equity at 9.9%.

The Commission also denied EAI's request to recover a number of expenses from its ratepayers, including reducing the level of incentive pay and stock options requested by EAI by over $21 million, and by rejecting EAI's request for its ratepayers to pay for entertainment expenses which included tickets to sporting events and concerts, golf balls and golf tournament expenses, and dinners and alcohol to entertain political figures.

Further, the Commission approved EAI's request to recover costs relating to projects and organizations that promote new technologies and research and

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development investment. The Commission indicates its support for the development of new technologies which could provide more efficient utility operation that will lead to direct ratepayer benefit. The expenses that the Commission's order allows EAI to recover include the cost of its recently-deployed "broadband over power lines" project which is designed to study the feasibility of utilizing this new technology to enhance service delivery, outage detection and service restoration, as well as the potential future deployment of cost-effective and efficient demand response technology and advanced metering capabilities.

Other recoverable cost items that promote research and development include EAI's membership in the Electric Power Research Institute and the Southeastern Electric Exchange, as well as the percentage of EAI's membership dues for the Edison Electric Institute and Nuclear Energy Institute which are not related to promotional or lobbying activities. These recoverable costs were directed tied to ratepayer benefit. The Commission's order further allows Entergy to recover all of its costs to comply with the Commission's new corporate affiliate rules.

The Commission also conditionally approved a new Production Cost Adjustment Rider ("PCA"), which is designed to allow for the recovery of the current cost mandated by the Federal Energy Regulatory Commission ("FERC") under Entergy's System Agreement. This PCA will be reviewed annually as a part of an Annual Earnings Review ("AER") process which will, among other things, include a review of all of EAI's actions towards withdrawing from or satisfactorily amending its System Agreement that is the basis of the FERC-ordered rough production cost equalization payments. Any excess

earnings identified through the AER process will be credited to ratepayers through the PCA Rider.

With respect to these FERC-ordered payments, the Commission reiterates its intent to continue to fight the FERC order which requires EAI to make payments to other Entergy operating companies. The Commission acknowledges that existing U.S. Supreme Court precedent establishes federal preemption over this Commission regarding recovery by EAI of the FERC required production costs payments to the other Entergy operating companies.

Finally, the Commission rejected EAI's proposed Capacity Management Rider as premature and not supported by substantial evidence. The Commission also amended EAI's Energy Cost Recover Rider ("ECR") and, as amended, allowed the ECR to continue for an additional year subject to the same limitations and conditions applicable to its approval of the PCA.

Procedural History

The parties to this proceeding are: Entergy Arkansas, Inc. ("EAI" or the "Company"), the General Staff of the Arkansas Public Service Commission ("Staff"), the Attorney General of Arkansas ("AG"), the Arkansas Electric Energy Consumers ("AEEC")[1], Kroger, the Commercial Group[2], and the Federal Executive Agencies ("FEA").

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[1]Members of AEEC are Acme Brick Company, Albemarle Corporation, Almatis, A. Tenenbaum Company, Inc., Arkansas Steel Associates, Bibler Brothers, Inc., Chemtura Corporation, CMC Steel – Arkansas, International Paper Company, Lion Oil Company, Norandal USA, Inc., Potlatch Corporation, Producers Rice Mill, Riceland Foods, Inc., Riviana Foods, Inc., Stratcor Incorporation, Temple-Inland Forest Products, and Weyerhaeuser Company.

[2]Members of The Commercial Group are JC Penney Corporation, Inc., Lowe's Home Centers, Inc., and Wal-Mart Stores, Inc.

On August 15, 2006, EAI filed in the above-styled Docket its Application for a general increase in the rates it charges for retail electric service[3]. In support of its Application, EAI filed the Direct Testimony and Exhibits of its witnesses, Mr. Hugh T. McDonald, Mr. J. David Wright, Mr. Phillip B. Gillam,[4] Mr. Gordon D. Meyer, Mr. Greg J. Grillo,[5] Mr. Roger A. Morin, Mr. Robert R. Cooper, Mr. Steven M. Fetter, Mr. Roger Q. Mills, III, Mr. Michael J. Goin, Mr. Michael M. Schnitzer, and Mr. Paul R. Ford.

The Commission issued Order No. 3 on September 14, 2006, suspending EAI's proposed rates and setting the initial procedural schedule. Order No. 4, issued on October 2, 2006, amended the initial procedural schedule and directed the Staff and Intervenors to file Direct Testimony by February 5, 2007; EAI to file Rebuttal Testimony by March 5, 2007; Staff and Intervenors to file Surrebuttal Testimony by March 26, 2007; and EAI to file Sur-Surrebuttal Testimony by April 2, 2007. The parties were further directed to file a detailed Joint Issues List by April 8, 2007. Order No. 4 also set an evidentiary hearing to begin April 24, 2007, at the offices of the Commission in Little Rock, Arkansas, and set public comment hearings to be held May 3, 2007, in El Dorado, Arkansas, and May 8, 2007, in Batesville, Arkansas. By Order No. 7, the Commission postponed the evidentiary hearing set for April 24, 2007, by one day, rescheduling the hearing to begin on April 25, 2007.

Pursuant to the procedural schedule, on February 5, 2007, the Staff filed the Direct Testimonies and Exhibits of its witnesses Mr. Robert H. Swaim, Mr. Clark Cotten, Ms. Anita J. Marshall, Ms. Elana Davis, Mr. Larry Walker, Ms. Adrienne R. W. Bradley,

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[3]EAI subsequently filed amendments to its Application on August 23 and August 25, 2006.

[4]EAI witness Gillam filed a revised Exhibit PBG-6 on December 7, 2006.

[5]EAI Witness Grillo filed *Supplemental Direct Testimony* on October 10, 2007.

Ms. Tanya Plunkett, Ms. Donna Gray, Mr. Jeff Hilton, Mr. Ralph C. Smith and Ms. Alice D. Wright. Also on February 5, 2007, Testimony and Exhibits were filed by AG witness Mr. William B. Marcus, by AEEC witness Mr. Randall J. Falkenberg, by the Commercial Group witness Mr. Glen E. Gregory, and by Kroger witness Mr. Kevin C. Higgins.

On March 5, 2007, EAI filed the Rebuttal Testimonies and Exhibits of its witnesses McDonald, Wright, Gillam, Morin, Meyer, Fetter, Grillo, Schnitzer, Cooper, Mr. Richard A. Lynch, Mr. Kurtis W. Castleberry, Mr. William M. Mohl, Mr. William A. Eaton, Mr. Kevin G. Gardner, and Mr. Jay A. Lewis.

On March 26, 2007, Staff filed the Surrebuttal Testimony and Exhibits of its witnesses Davis, Cotten, Plunkett, Swaim, Smith, Walker, Wright, Hilton, Bradley[6], Marshall, and Gray. On that same date, the AG, AEEC, the Commercial Group, and Kroger, and the FEA filed the Surrebuttal Testimony and Exhibits of their respective witnesses, Marcus, Falkenberg, Gregory, Higgins and Mr. Larry Blank. Staff witness Hilton subsequently adopted the Direct and Surrebuttal testimonies of Ms. Plunkett at hearing.[7]

On April 2, 2007, EAI filed the Sur-Surrebuttal Testimonies and Exhibits of witnesses Mohl, Meyer, McDonald, Grillo, Gillam, Schnitzer, Wright, Morin, Lewis, Fetter, Castleberry, and Lynch.

On April 9, 2007, the General Staff, on behalf of all parties, filed the Joint Issues List and thereafter, on April 23, 2007, filed an Amended Issues List.

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[6]On March 29, 2007, Staff witness Bradley filed an Errata sheet, replacing page 6 of her Surrebuttal Testimony.

[7]References cited to Ms. Plunkett in this Order are to her pre-filed Direct and Surrebuttal Testimonies which were fully adopted by Mr. Hilton who sponsored the positions contained therein and was subject to cross examination on those positions.

On April 25, 2007, the evidentiary hearing on EAI's Application was commenced at the Offices of the Arkansas Public Service Commission (the "Commission" or the "APSC") in Little Rock and continued through May 4, 2007.

Pursuant to Ark. Code Ann. §23-2-103 (b), public comments were heard by the Commission during the evidentiary hearing in Little Rock, Arkansas, and during public comment hearings in El Dorado, Arkansas on May 3, 2007, and in Batesville, Arkansas on May 8, 2007. During the Little Rock evidentiary hearing six individuals commented on EAI's rate case Application. Of those, five spoke in favor of EAI's Application and one spoke requesting that the Commission keep in mind the impact of the issues before it on low income Arkansans. During the El Dorado public comment hearing three individuals commented on EAI's Application. All three supported the Application. During the Batesville public comment hearing five individuals commented on EAI's Application. Of those, four spoke in favor of EAI's Application and one individual urged the Company and the Commission to begin to focus attention on renewable energy and distributed generation. In addition the Commission received a total of thirty-five email or telephone comments on EAI's Application. All thirty-five opposed approval of the Application.

Though highly valued by the Commission the "public comments" of utility customers do not rise to the level of substantial evidence upon which the Commission is required by law to base its decision. The Commission cannot base its decisions upon the public comments of utility customers without violating the due process rights of the utility or other official parties to the rate case proceeding. Public comments are not subject to pre-hearing discovery by the official parties, and are not subject to adversarial

cross-examination by the official parties during the evidentiary hearing. Thus, public comments do not constitute substantial evidence upon which the Commission can lawfully base its rate case decisions. The rate case decisions of the Commission must be based upon substantial evidence of record and must fall within the rate case boundaries or parameters prescribed by the Constitution of the United States as interpreted by federal and Arkansas courts. Although not substantial evidence of record, the Commission does take such public comments into consideration in its efforts to reach a balanced rate case decision that is lawful and fair to both the utility and its customers. Public comments can certainly be helpful to the Commission regarding quality of service issues, as well as cost allocation and rate design issues that can be decided within a "range of reasonableness." However, even these issues must be supported by substantial evidence of record.

Revenue Requirement Calculations, Cost of Service and Rate Design

The primary purpose of this docket is to determine whether EAI is entitled to an increase in its base rates for retail electric service. Unlike automatic adjustment clauses or riders, base rates are fixed by the Commission and do not vary from rate case to rate case. Base rates are determined by first establishing the appropriate retail revenue requirement. The revenue requirement is calculated taking into consideration the expected, normal level of utility-related expenses plus an appropriate rate of return on the expected, normal level of rate base. Rate base is the utility's financial investment in utility-related assets, both long- and short-term. The rate of return is calculated using the weighted cost of funds of the utility, made up of the proportional equity return, or profit, and related income tax, cost of debt, and cost of other liabilities, including those

which are available at zero cost. Expenses, investment, and cost of funds are measured based on a utility-selected test year of actual costs, adjusted to recognize all known and measurable changes occurring within 12 months following that test year.

Once the revenue requirement is established, it is then assigned or allocated between the utility's Arkansas jurisdictional operations and any other jurisdiction, with the Arkansas allocated revenue requirement then assigned or allocated to each of the utility's rate classes under this Commission's jurisdiction. Components of the revenue requirement are assigned and allocated inter-jurisdictionally and to each class either directly to the jurisdiction or class incurring the cost or using factors which appropriately reflect general cost causation.

Rates are then established for each rate class using the amount of revenue requirement allocated to each class. Rate design differentiates customer related costs from those used to meet demand on the system and those used to provide each unit of energy. The resulting rate structure for each class will, where appropriate, reflect customer charges, demand charges, or unit of energy charges.

EAI's Rate Request

By its Application, EAI initially requested an increase in its current retail rate schedule revenues[8] of $150,366,000 based on its calculated revenue requirement of $1,053,942,000 (Minimum Filing Requirements ("MFR") Schedule A-1, ln 13), for an overall increase in its Arkansas retail rates of approximately 14.23%[9]. Subsequently, EAI amended its request in its Rebuttal Testimony, adjusting its proposed rate schedule

[8]Current rate revenues for Arkansas retail service, as reflected on MFR Schedule G-1, page 1, are $903,576,000.

[9]$150,366,000 requested increase divided by $903,576,000 current rate revenues.

revenue requirement to $1,010,110,000 and its projected revenue deficiency to $106,534,000 resulting in an increase in its current Arkansas retail rates of 11.79%.[10] EAI's projected revenue deficiency or rate increase is based on the Company's estimated pro forma rate base of $3,654,345,000, rate schedule revenues of $903,576,000, expenses of $771,188,000, other revenues of $37,435,000 and a required overall return of 6.42%, which is calculated using an equity return of 11.25% and a capital structure with a debt to equity ratio of 44% to 56%.

The Staff submits a fully developed EAI revenue requirement[11] in which it recommends a rate schedule revenue requirement of $925,794,000, with an expected revenue deficiency or rate increase of approximately $2,005,000. Staff's recommended $2,005,000 rate increase is based on a pro forma rate base of $3,693,152,000, operating revenues of $960,414,000, expenses of $755,621,000, and other revenues of $36,624,000. (T. Ex. 1146) Staff proposes an overall rate of return of 5.58%, which is calculated using an equity return of 9.90% (T. 829) and a capital structure with debt to total capital ratio of 52% to 48%. (T. 849) Staff's recommended rate schedule revenue requirement is approximately $84,316,000[12] less than that proposed by EAI.

As provided in the Amended Issues List, contested revenue requirement components are the capital cost, including equity return, the debt to equity ratio, adjustments to the Entergy Money Pool, and use of the Modified Balance Sheet Approach ("MBSA"), with the related elements and levels of zero-cost funds; rate base,

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[10] T. Ex. 903.

[11] The AG and CEUG each addressed certain components of EAI's proposed revenue requirement request.

[12] Staff's rate schedule revenue requirement of $925,794,000 less EAI's rate schedule revenue requirement of $1,010,110,000.

including pro forma plant and retirements and related accumulated depreciation, the levels and elements of Working Capital Assets ("WCA"), the recognition and treatment of certain costs deferred by EAI and included in rate base for prospective amortization; and expenses, including pro forma depreciation, payroll levels, incentive pay treatment, pro forma levels of storm damage expense, treatment of certain civic and industry organization dues, donations, and club memberships, costs related to Affiliate Rules compliance, Director and Officer liability insurance expense; other revenues; and income tax, including the prospective application of the normalization method for taxes and the manufacturing deduction, for calculation of both income tax expense and as part of the gross conversion factor.

Other contested issues include billing determinant levels and related revenues and cost of service allocations; overall cost of service methods affecting inter-class allocation of production costs, transmission costs, the storm damage reserve; certain customer service and service revenue accounts; and certain tariffs and riders, including EAI's proposed Production Cost Adjustment ("PCA") rider, Capacity Management ("CM") rider, Energy Cost Recovery ("ECR") rider, Irrigation Control Service rider ("M25"), Service Extension tariffs, and tariff issues related to EAI's exemption to the Commission's Master Metering rules. Also contested is the wholesale/retail allocation and the recovery of Entergy System Agreement payments ("FERC Payments") as ordered by the Federal Energy Regulatory Commission ("FERC") in its Opinion 480 and 480-A[13] (the "FERC Decision").[14] (T. 2842)

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[13]Opinion No. 480,111 FERC 7 61,311, *afd* Opinion No. 480-A, 113 FERC 7 61,282 (2005).

[14]As a result of the FERC Decision, EAI will be required to make payments to other Entergy Operating Companies ("EOCs") for certain imbalances in production costs among the EOCs to begin in June, 2007,

Revenue Requirement

Cost of Capital

The purpose of the cost of capital or rate of return calculation is to compensate the utility for its costs of capital used to finance its investment, or rate base. Those sources are generally on the liabilities side of the balance sheet, while the rate base generally encompasses items on the assets side of the balance sheet.

Generally, there are four main components to the capital structure used to calculate the overall cost of capital, or rate of return: common equity, preferred stock, debt, and accumulated deferred income taxes ("ADIT"). Common equity represents the investment made by the common shareholders; preferred stock is a type of financial instrument with some characteristics of equity and some characteristics of debt; debt encompasses specific long-term and short-term sources of debt; and ADIT is a zero-cost source of capital which reflects timing differences in the calculations of income taxes. Depending on the utility, other capital components may be included.

The various capital components are weighted by the respective proportions in the overall capital structure, each capital proportion is then multiplied by its capital cost, and then summed over all capital components to determine the rate of return. Generally, all of the capital costs, except for the cost of common equity, are readily obtainable from financial and accounting records; the cost of common equity must be inferred from market data.

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pursuant to the Company's proposed Compliance Filing now pending before the FERC. The EOCs include: EAI; Entergy Gulf States, Inc.; Entergy Louisiana, LLC (formerly Entergy Louisiana, Inc.); Entergy Mississippi, Inc.; and, Entergy New Orleans, Inc.

Cost of Common Equity

The purpose of the cost of equity calculation is to allow the utility the opportunity to earn a return that is commensurate with the returns earned by companies of comparable risk. This will allow the utility the opportunity to attract capital on financially reasonable terms and compensate it for that portion of its capital. Unlike other components of the cost of capital, the cost of equity, which is designed to reflect investors' expected return, can only be estimated.

Because the cost of equity is not explicitly stated, it must be inferred from a variety of market data, with the assistance of expert witnesses. A number of methodologies for calculating the estimated cost of equity are used by the witnesses in this case; which include: (1) the Discounted Cash Flow ("DCF") methodology; (2) the Risk Premium methodology; (3) the Capital Asset Pricing Model ("CAPM") methodology; and (4) the Comparable Earnings methodology. Each of these methodologies, with each witness's corresponding results and recommendation, is considered in turn.

The parties to this proceeding recommended various costs of equity allowances. EAI witness Morin recommended a cost of equity of 11.25%. (T. 363) Staff witness Gray recommended 9.9%, which is the midpoint of her recommended range of 9.6% to 10.2%. (T. 830) AG witness Marcus recommended 9.5% (T. 672) and Commercial Group witness Gregory recommended 10.0%. (T. 588) While allowed return on equity ranges may be inferred from the testimony of the witnesses, Staff is the only party that explicitly stated a range. (T. 840, 873-874)

Discounted Cash Flow Methodology

The DCF methodology calculates the cost of equity as the sum of the dividend yield and the investor-expected growth rate (or growth rates, if a non-constant growth rate model is employed). The growth rate is a key component of the formula, and there is not one generally-accepted source for determining this growth rate. Hence, cost of equity witnesses must reasonably infer the investor-expected growth rate from published data.

Additionally, the DCF Methodology contemplates the use of a sample of companies comparable in risk to the Company in question, which in this case is EAI. The reason to use companies comparable in risk to EAI is the well-established principle of a positive correlation between investor-perceived risk and the required return on equity, or cost of equity. Generally, investors are risk averse, which implies that investors require greater returns from those common stocks that are riskier. Further, companies that are approximately equal in risk should have approximately equivalent required returns.

In developing risk-comparable samples, it is important to realize that there is not just one correct risk-comparable sample. A number of samples may be considered reasonable as long as each company in the sample is approximately equal in risk to the Company in question. Additionally, it is not necessary that each and every company in the sample be precisely equal in risk to the Company in question. However, the Commission would expect that, taken as a whole, the sample should be approximately equal in risk to the Company in question.

EAI witness Morin used two risk-comparable groups. First, he used a group of twenty-five electric and natural gas utility companies with predominately integrated utility activities, with bond ratings of Baa3 or above, with only parent companies, with market capitalizations greater than $500 million, and with at least 50% of their revenues from regulated electric utility operations. (T. 329, T. Ex. 97-105) Dr. Morin's dividend yield for this group is 4.4%. (T. 352, T. Ex. 109-111) Second, Dr. Morin used the electric utilities that make up the Moody's Electric Utility Index. His dividend yield for that group is 4.4%. (T. Ex. 115-117)

Staff witness Gray used two risk-comparable groups. First, Ms. Gray used a sample of ten companies listed in *Value Line Investment Survey*, with at least 75% of operating revenues from electric operations, with at least an S&P bond rating of BBB, with a stable or increasing dividend history, and not currently involved in merger activity. (T. 823-825) Those dividend yields are presented in Exhibit DG-12. (T. Ex. 378) Ms. Gray's second group is a sample of twenty-eight companies listed in *Value Line*, with current cash dividends, with no reductions in cash dividends in the last five years, and with no current involvement in merger activity. (T. 828) Those dividend yields are presented in Gray's Exhibit DG-16. (T. Ex. 382)

Commercial Group witness Gregory used two samples of risk-companies. First, Mr. Gregory used those with a *Value Line* Financial Strength Rating of B+ or greater, with five year earnings per share ("EPS") growth estimates from both Zach's Investment Service and Thomson Financial Services (First Call), with current cash dividends, with a current beta of 1.0 or less, and with no current involvement in merger activity. The

second group was developed by removing the beta requirement. Those dividend yields are shown in Gregory's Schedules GEG-1 and GEG-2. (T. Ex. 208-209)

Company witness Morin argues that the Staff's common stock price data is not current enough since it uses stock prices reaching back thirteen weeks. Dr. Morin also argues that current stock prices should be consistent with the estimate of growth that is paired with it. (T. 395-396) Staff witness Gray responds that it is appropriate to use a fairly current price term and a price term that averages out daily aberrant prices. Further, Ms. Gray argues that a current stock price may be efficient in that it represents that day's investor-expected cost of equity; yet the allowed return on equity is set for a period much longer than one day. Ms. Gray explains that the stock price should be averaged over an appropriate period of time and should be a period after the publication of professional growth prognosticators, *i.e.*, Value line, Zack's, etc., since the stock price is influenced by those expected growth rates. (T. 878) The Commercial Users witness Gregory makes the same arguments as Ms. Gray. (T. 621-622)

The Commission agrees with Staff witness Gray that the DCF price term should be averaged, from a fairly recent time period, and from a period after the reporting of growth rate estimates. Ms. Gray's analysis accomplishes that and is an appropriate approach. From the record developed in this case by the Company, it is not clear that Dr. Morin met these conditions for the price term in his DCF analysis.

Another difference among the witnesses concerns the appropriate growth rate adjustment to the dividend yield term. Mr. Gregory makes no direct adjustment using the 2007 annual dividend projected for each stock as reported in recent editions of *Value Line*. Ms. Gray uses a quarterly adjustment where dividend yield is equal to D (1

+ g/4)/P. (T. 823, 877) Dr. Morin uses an annual adjustment where the dividend yield is equal to D (1 + g)/P. (T. 345)

Dr. Morin criticizes the quarterly adjustment and alleges that it understates the appropriate adjustment. (T. 392-396, 465-467) Ms. Gray responds that the model maintains consistency of the quarterly cost of equity with the revenue requirement determination and has been consistently used by this Commission for the past twenty years.

The Commission is unconvinced by Dr. Morin's arguments that the quarterly cost of equity approach is flawed and continues to believe that it is the appropriate approach. In particular, Dr. Morin alleges that the approach contains a serious error. (T. 467) Dr. Morin asserts that if the investor-required quarterly cost of equity is 3%, that the allowed return on equity should be (1.03)4 -1 = 1.1255- = 12.55%. Dr. Morin's interpretation is flawed. For example, if investors receive these quarterly returns as dividends, then investors have the opportunity to re-invest these dividends in the Company's stock, or other financial instruments as they see fit. Consequently, investors may implicitly take advantage of compounding through the receipt throughout the year of dividends every quarter. The quarterly cost of equity approach appropriately considers that early receipt of dividends.

All witnesses rely solely upon EPS forecasts by professional analysts. The Company uses EPS forecasts from *Value Line* and Zach's. Staff uses four different approaches for estimating the investor-expected growth rate for application to the DCF methodology. All involve projected growth rates in EPS derived from Value Line, Zach's and S&P. (T. 827-828) The Commercial Group witness uses projected EPS forecasts

from Zach's and First Call. (T. 580) No witness uses historical data, book value per share growth rates, or dividends per share growth rates.

Company witness Morin alleges that Staff used a stale year, 2003, and stale *Value Line* data for purposes of calculating the g1 growth rate. (T. 401, 467-468) Staff witness Gray responds that g1 is the same as one of his growth rates and is based on recent *Value Line* issues (from August and September, 2006) wherein a base period of three years is reported. (T. 824, 879)

The Commission agrees with Ms. Gray. Dr. Morin apparently believes that Ms. Gray uses an older edition of *Value Line* (from 2003). That is not correct, as can be seen from the prefiled Direct Testimony of Ms. Gray. (T.824) Further, *Value Line* reports these three-year base estimates in current *Value Line* editions. This can be seen in Surrebuttal Exhibit DG-44, p. 9 of 12, for the example of Exelon. In the far left hand column annual rates of change in earnings are reported for the period "03-05" to "09-11". (T. Ex. 433) As can be seen there Exelon's growth rate is 6.0%. Dr. Morin misunderstands Staff's data sources and, hence, his criticisms are invalid. Additionally, Dr. Morin claims that g1 and g4 are the same projections, with g1 merely being an older version of g4. (T. 467-468) This assertion is incorrect since all of the data come from the same editions of *Value Line*, as discussed earlier, and are separate sets of growth rate data that investors would likely rely upon. Consequently, for all of the above reasons the Commission disagrees with Dr. Morin that Ms. Gray's g1 growth rates should be disregarded.

Ms. Gray criticizes EAI witness Morin's DCF analysis for the inappropriate inclusion of firms that were either rated below investment grade or involved in merger

activity. Staff also criticizes the inclusion of the FPL Group, which has been involved in merger activity. Correcting Dr. Morin's Exhibits RAM-6 and RAM-7, RAM-8, and RAM-9 solely for those errors results in DCF cost of equity estimates of from 9.4 % to 10.0 %. (T. 873-874) Dr. Morin testifies that these firms should be included because they are currently either not below investment grade or are not currently involved in merger activity. (T. 417) Staff witness Gray responds that *at the time* that Dr. Morin performed his analysis these firms should not have been included. (T. 873, T. Ex. 425-436)

Company witness Morin also states that during periods when the ratio of a utility's market price to its book value ("M/B") is greater than 1.0, the DCF methodology understates the cost of equity. Dr. Morin testifies that this is particularly relevant at the present time when electric utility stocks are trading at M/B ratios above 1.0. (T. 354-356, 470) Commercial Group witness Gregory responds that investors are fully aware of the fact that regulatory commissions allow the return on the utility's investment and not on what the investor paid for his or her shares; consequently, the DCF method does not underestimate the cost of equity during periods when M/B is greater than 1.0. Further, if regulatory commissions were to make the M/B adjustments recommended by Dr. Morin, an endless cycle of increasing M/B ratios would result. Finally, Mr. Gregory notes that only a few regulatory commissions accept Dr. Morin's view. (T. 622-623)

Mr. Gregory's assessment on this point is correct. If the Commission were to make M/B adjustments, it would result in a never-ending cycle of increasing M/B ratios and a never-ending cycle of increasing allowed returns on equity. Consequently the Commission rejects Dr. Morin's argument that the DCF methodology systematically understates the cost of equity during periods when M/B is greater than 1.0

Further, on this point the Commission believes that the converse would also be true: during periods when electric utilities' M/B ratios are *less* than 1.0, the DCF methodology would *overstate* the cost of equity. We do not recall APSC-jurisdictional utilities, or for that matter EAI, making such an argument during the 1980's when electric utilities' M/B ratios were less than 1.0.

Risk Premium Analysis

The risk premium method is premised on the assumption that ownership of common stock is generally riskier than ownership of corporate debt. Because it is riskier, common stock requires a higher return than does corporate debt. If that difference in required return, the risk premium, can be adequately measured, it can be simply added to the measurable corporate bond rate to estimate the required return on common equity.

Company witness Morin utilized two risk premium analyses. One analysis was based on historical time series data using Moody's Electric Utility Index as a proxy. The second analysis employed allowed returns on equity.

For the historical analysis, Dr. Morin determined that the risk premium was 5.6% over long-term U. S. Treasury Bonds. With a current long-term U.S. bond yield of 5%, Dr. Morin derives a 10.6% risk-premium-based cost of equity. (T. 339)

Using allowed returns on equity relative to U.S. Treasury Bond yields over the period 1996-2005, Dr. Morin determines that there is an average 5.5% risk premium. He also states that there is a statistically significant relationship between risk premiums and interest rates using regression analysis. Utilizing the current 5% long-term U.S.

Treasury Bond yield in his regression model, Dr. Morin obtains a current risk premium of 5.9% and a 10.9% risk premium-based cost of equity. (T. 340-342, 419-420)

Staff witness Gray does not support the use of the risk premium approach as a primary indicator of the required return on equity because accurate measurement of the risk premium is a problem, and risk premiums are not stable over time. Ms. Gray testifies that estimates of the risk premium can vary based on the historical time period used for measurement, the underlying securities, and the end points used. She points to Dr. Morin's Exhibit RAM-3 where equity risk premiums varied from -37.34% to 71.96%, and where over 34% of the observations have negative risk premiums. (T. 831-832)

In her Direct Testimony, Ms. Gray also corrects a number of errors in Dr. Morin's historical risk premium data and, with those corrections, replicates his analysis in Staff Exhibit DG-23. This yields a historical risk premium of 4.99%. (T. 34-35) Adding this to her risk-free rate of 4.74% results in a 9.7% cost of equity. With regard to Dr. Morin's allowed return on equity analysis, Ms. Gray takes exception to his approach because six of the reported allowed returns on equity are the result of reaching either a stipulation or settlement. Nevertheless, using Dr. Morin's 5.54% risk premium with the risk-free rate of 4.74% supported by Staff produces a 10% cost of equity estimate. (T. 836)

Dr. Morin disagrees with Ms. Gray's risk premium discussion in a number of areas. First, Dr. Morin asserts that historical risk premiums are stable. Dr. Morin also states that, after correcting the errors and updating the results, the same historical risk premium of 5.5% to 5.6% was obtained. Dr. Morin testifies that using allowed returns on equity are accurate reflections of what relevant regulatory regard as fair and reasonable returns. Finally, EAI witness Morin corrects Ms. Gray's correction from 10%

to 10.28% and calculates a risk premium analysis with Ms. Gray's risk-free rate to obtain a 10.8% cost of equity. (T. 420-421)

AG witness Marcus quotes from a number of studies with findings of risk premiums in the 2.4% to 4.5% range. (T. 662-663, T. Ex. 285-318) Mr. Marcus criticizes Dr. Morin's historical risk premium analysis because it erroneously assumes a constant risk premium, uses data that precede the Great Depression, and is incorrectly estimated. (T. 664)

Commercial Group witness Gregory developed a risk premium of 4.20% based on the average risk premium from the most recent five years. Mr. Gregory adds this to the current single "A" rated utility bond yield of 5.73% to produce a risk premium-based cost of equity of 9.99%. This estimate is used by Mr. Gregory to confirm his DCF results. (T. 586-587)

Capital Asset Pricing Model

The Capital Asset Pricing Model ("CAPM") is an academic embellishment of the risk premium method which attempts to measure different risk premiums for different companies based on those particular risks of those companies. The CAPM is defined as "$K = Rf + \beta (Rm - Rf)$" where 'K' is the required return on equity, 'Rf' is the risk-free rate, 'Rm' is the market return, 'β' is the beta factor, and 'Rm –Rf' is the market risk premium. The market risk premium used in the CAPM is the difference between the overall stock market-required return and the risk-free rate. The beta of a common stock measures the volatility of the common stock price relative to the volatility of the stock market in general. A beta greater than 1.0 indicates that the stock price is more volatile

than the market; a beta less than 1.0 indicates that the stock price is less volatile than the market.

Company witness Morin uses actual and forecasted yields on 30-year U.S. Treasury Bonds for the risk-free rate, which was 5.0% in his analysis. Dr. Morin uses a beta of .85 using the same risk-comparable group of electric utilities he uses in his DCF analysis. Dr. Morin checked that with the average beta of electric utilities in Moody's Electric Utility Index. For the market risk premium Dr. Morin uses 7.5%, which was based on a variety of forward-looking and historical studies of long-term risk premiums. Dr. Morin's CAPM result is 5.0% + .85 X 7.5% = 11.4%. (T. 323-335)

Dr. Morin also utilizes an empirical form of the CAPM ("ECAPM") in his analysis. Based on some of the academic literature, statistical tests purportedly demonstrate that the beta line is not as steeply-sloped as predicted in the theoretical CAPM. The implication of this approach is that firms with low-betas (below 1.0) earn returns somewhat higher than the theoretical CAPM would predict. Using the mathematics predicated on the ECAPM, Dr. Morin estimates his ECAPM as 11.7%. (T. 335-338, T. Ex. 139-155)

Commercial Group witness Gregory performed a CAPM analysis with a long-term risk-free U.S. Treasury Bond rate of 4.88%, a beta of .74, and a risk premium of 6.5%, which results in a CAPM cost of equity of 9.66%. (T. Ex. 211) Mr. Gregory disagrees with Dr. Morin's 7.5% risk premium. (T. 593-594) Mr. Gregory also notes a general deficiency in the CAPM methodology since reported beta calculations are strictly historical and do not predict future betas. Therefore, the forward-looking DCF

methodology should receive more weight than the CAPM and other historic risk premium methodologies. (T. 626)

AG witness Marcus performed a CAPM analysis using a risk-free rate of 5.0%, a beta of .85, and a variety of risk premiums. Mr. Marcus generated a range of CAPM results of 8.05% to 9.71%. (T. 670-671)

Staff witness Gray performed a CAPM analysis as a reasonableness check on her DCF results. Ms. Gray used the 30-year U.S. Treasury bond yield of 4.74% for the risk-free rate, a beta of .80 to .85 based on the Entergy beta, and a market risk premium of 5.9% based on data from Ibbotson Associates. Ms. Gray's CAPM estimate is 9.5% to 9.8%. (T.833-835) Ms. Gray also replicated Dr. Morin's ECAPM analysis using her formula inputs, resulting in an ECAPM estimate of 9.8% to 10.0%.

Dr. Morin disagrees with all three of Ms. Gray's inputs in her CAPM analysis. In particular, Dr. Morin claims that the risk-free rate should be a current 4.9%, that the beta should be .90, and that the risk premium should be 6.5%. Dr. Morin then obtains a 10.8% estimate of his revision of Ms. Gray's CAPM analysis. (T. 409-411) Dr. Morin also disagrees with AG witness Marcus's CAPM analysis. In particular, Dr. Morin disagrees with Mr. Marcus' use of actuarial data, his market risk premium estimate, and his use of geometric averages in measuring expected return. (T. 428-430) Finally, Dr. Morin takes issue with Commercial Group witness Gregory's CAPM analysis, claiming that it understates the cost of equity by 40 basis points. (T. 446-449)

Other Methods and Checks

Commercial Group witness Gregory produces a Comparable Earning Test estimate of 10.2%. Mr. Gregory was the only witness to perform this test. (T. 585)

AG witness Marcus presented a study based on the estimated stock returns that Entergy and other utilities use to compute pension fund and nuclear decommissioning fund requirements. Mr. Marcus obtained return estimates of from 8.5% to 9.9%. (T. 656-670)

EAI witnesses Morin and Fetter allege that Ms. Gray's recommended allowed return on equity is harsh and below the mainstream of recently allowed returns on equity. (T. 382-385, 276-279) Ms. Gray responds that reliance upon the allowed returns of other Commissions is circular and that many of the reported allowed returns may be the result of stipulations or settlements with give and take among settling parties, including give and take with regards to the cost of equity. Ms. Gray also notes that that the information relied upon does not support the Company's request and that the 2006 allowed returns are in the range of 10.06% to 10.44%, which is more consistent with Staff's recommended range.

Flotation Cost Adjustment

A flotation cost adjustment is an addition to the cost of equity that attempts to reflect the issuance costs associated with a company's issuances of common stock.

Company witness Morin argues for a flotation adjustment to the cost of equity of 30 basis points. (T. 351-353) This adjustment would result in a $7 million annual impact on Arkansas ratepayers. (T. 596, 838) Dr. Morin argues that his floatation cost adjustment consists of two parts. The first reflects underwriting expenses and the second reflects market pressure. (T. 356-361, T. Ex. 156-166)

Staff witness Gray opposes the adjustment for underwriting expenses. Ms. Gray testifies that EAI's last common stock issuance was in 1983, that EAI actually

repurchased common stock in 1990, that EAI currently has no planned issuance of securities in the pro forma year, and that Entergy Corp. issued no common stock shares from 2003-05. Ms. Gray also testifies that the shares issued in the past 10 years by Entergy were for the dividend reinvestment stock purchase plan, employee stock investment plan, and stock option expenses. Ms. Gray notes that: Entergy actually repurchased common shares during 1998-2005; Entergy has no planned issuance of securities during the pro forma year; Entergy plans to continue stock repurchases during the pro forma year; and Entergy has not publicly issued common stock for more than twenty years. (T. 839-840) Ms. Gray also opposes the market pressure component of the flotation cost adjustment recommended by the Company because it is difficult to disentangle the market pressure effect from other effects that could affect a utility's stock price at the time common stock is issued. (T. 839-840)

Dr. Morin responds to Ms. Gray by stating that there are a number of studies that support market pressure impacts of between 1% and 3%. (T. 422-423)

Commercial Group witness Gregory argues that a flotation adjustment is not needed in this case for two reasons. The first reason is that there have been minimal stock flotation costs over the past ten years. The second reason is that Entergy has decreased the number of shares outstanding during the past ten years. (T. 595-596) However, Mr. Gregory states that if the Commission finds that a flotation cost adjustment is warranted, he would recommend a ten basis point adjustment rather than EAI's request for an adjustment of thirty basis points. (T. 596)

Based on the evidence presented by Staff and the Commercial Group, the Commission finds that a flotation adjustment is not appropriate in this case.

Commission Determination of the Allowed Cost of Equity

The Commission heard extensive testimony on cost of equity. As this Commission has done in the past, we continue to rely primarily on the DCF methodology. While all methodologies used to estimate the cost of equity have weaknesses, in our opinion, the DCF methodology has fewer weaknesses than other methodologies. The risk premium and CAPM methodologies rely on a number on inputs about which witnesses disagree widely, including the risk-free rate, the risk premium, and the beta. Furthermore, this Commission does not rely upon the comparable earnings method because it relies upon earned returns, rather than required returns, and is circular in nature.

A major advantage of the DCF methodology is that it is more directly market-based. A key component of the DCF formula is the price term. The price term, if correctly calculated, is *forward-looking* and directly embodies the market consensus of a utility's risk, the time value of money, and the opportunity cost of money. As can easily be seen from the DCF formula, $K = D/P + g$, if risk increases, P decreases, and K increases. If the time value of money increases, P decreases, and K increases. If the opportunity cost of money increases, P decreases, and K increases. All of these results illustrate the simplicity of the DCF methodology. None of the other methodologies employ such a simple and direct market-based measure. Instead they all are *backward-looking*, relying upon a vast array of historical data, which may or may not be applicable in the future.

The only major issue that may arise in utilization of the DCF methodology is the estimate of the investor-expected growth rate. Witnesses often develop different estimates of the investor-expected growth rate. That is not true in this case.

With regard to the mechanics of some of the inputs to the DCF methodology in this case, the Commission agrees with Staff and the Commercial Group that the price term should be recent and averaged over a period of time to remove temporary price aberrations. The Commission also agrees with the Staff with regard to the quarterly form of the dividend yield term. As discussed above, a floatation cost adjustment is not adopted in this case. Finally, we agree with Staff with regard to the composition of EAI's two risk-comparable samples. After including Staff's corrections to Dr. Morin's DCF calculation, the result is a DCF cost of equity range of 9.4% - 10%, which is consistent with Staff's recommendation. (T. 830, T. Ex. 385-388) Commercial Group witness Gregory's DCF range (using medians and means) is 9.19% to 10.0%, which is also consistent with Staff's range. (T. 580)

With the corrections to Dr. Morin's DCF analysis, the DCF results by party are: EAI's range is 9.4% to 10.0%; Staff's range is 9.6% to 10.2%; and the Commercial Group range is 9.19% to 10.0%. The intersection of these three ranges is 9.6% to 10.0%. The similarity of these three witness's DCF cost of equity estimates implies that there is very little difference, if any, in their growth rate estimates.

The Commission also agrees with the corrections that Staff witness Gray made to Dr. Morin's risk premium, CAPM, and ECAPM methodologies, and in particular the risk premiums Dr. Morin relied upon. Based on those corrections, Ms. Gray calculates Dr. Morin's risk premium, CAPM, and ECAPM results as being from 9.5% to 10.0%. (T. 837)

Ms. Gray's own risk premium, CAPM, and ECAPM results are in the range of 9.5% to 10.0%. (T. 834-835) Commercial Group witness Gregory's risk premium and CAPM analysis produced a range of 9.66% to 10.0%. (T. 588) The AG presents evidence for a CAPM cost of equity range of 8.05% to 9.71%. (T. 671)

Given this Commission's primary reliance on the DCF methodology, and noting the results of the risk premium and CAPM methods as a check on the DCF results, the Commission finds that an allowed cost of equity in the range of 9.6% to 10.2% is reasonable in this case.

Furthermore, the Commission notes that there is one other matter that is important to consider. As noted by Ms. Gray, approximately 40% of EAI's revenues to be collected from EAI retail ratepayers will be collected through automatic adjustment clauses (the PCA, ECR, and other existing riders). There is no doubt that automatic adjustment clauses make utilities less risky, which implies a correspondingly lower cost of equity. In this case, 40% of EAI's revenues are at minimal risk of sales fluctuations or fuel cost fluctuations. Because of this reduced risk, we believe that an allowed return on equity of 9.9%, the mid-point of Staff's 9.6 to 10.2% range, is appropriate in this case. This return is commensurate with returns on utilities comparable in risk. Further, as discussed in our section concerning the capital structure, this return will maintain and support EAI's credit rating and allow it to continue to attract capital.

Capital Structure/Debt to Equity Ratio

A key aspect of the overall rate of return calculation is the determination of the appropriate capital structure. It is incumbent upon this Commission to ensure that the capital structure is reasonable, since it significantly affects the rates charged to the

Company's customers. The appropriate debt/equity ratio to be used in the capital structure is often contested by the parties since: (1) the cost of common equity is greater than the cost of debt and (2) the cost of equity is "marked-up" in the calculations of revenue requirement to cover income taxes, while the cost of debt is not. A smaller debt/equity ratio, other things being equal, will necessarily increase the overall cost of capital, and, ultimately customers' rates. In this case, EAI argues for a smaller debt to equity ratio than do the other parties.

EAI's basis for calculating its debt to equity ratio is a forecast of capital proportions as of June 30, 2007.[15] Furthermore, the actual debt to equity ratio as of June 30, 2006 reflected in the MFR, Schedule D-1 (a) is 45.5/54.5% rather than EAI's requested 44/56% ratio, which is a slightly higher debt proportion.

The parties in this case have recommended a variety of debt-to-equity ratios. They range from 44% debt and 52% equity as advocated by EAI to 52% debt and 48% equity as recommended by Staff and the AG. These ratios are expressed on a comparable basis, wherein the percentage equity component includes common equity and preferred equity, and the percentage debt component includes all interest-bearing debt, such as long-term debt, capital leases, and the Department of Energy ("DOE") obligation. The DOE obligation is a financial obligation that EAI has for spent nuclear fuel disposal services associated with the Company's nuclear units ANO-1 and ANO-2.

Staff witness Gray testifies that there are a number of reasons for rejecting EAI's proposed debt to equity ratio and using her hypothetical debt to equity ratio of 52/48%. First, in EAI's last two rate cases in which an order was issued making an explicit finding

[15] MFR Schedule D-1-(a)

on the overall cost of capital, the debt to equity ratios were 55/45% and 52/48% in Docket Nos. 84-199-U and 96-360-U, respectively. (T. 814-815) Additionally, in the two most recent Arkansas electric utility rate cases, the debt to equity ratios were 51/49%. [16](T. 815)

Ms. Gray testified that the four-quarter debt to equity ratio average ending September 30, 2006, for her risk-comparable sample is 52/48% and the four-quarter debt to equity ratio average ending September 30, 2006 for her broader industry sample is 52/48%. (T. 815) Ms. Gray also found that the debt to equity ratio of Entergy Corp., EAI's parent company, for the four quarters ending September 30, 2006 is 52/48%. (T. 816)

Ms. Gray notes that recognizing the parent-only amount of debt that Entergy Corp. uses for its investment in EAI yields a debt to equity ratio of 53/47%. (T. 816-817) Ms. Gray states that the consolidated parent corporation's total debt to total capital ratios were in the range of 51% to 61% for the years 1996 through 2001. (T. 860)

Ms. Gray testifies that the total debt to total capital ratios for EAI based on Form 10-Ks filed at the Securities and Exchange Commission ("SEC") were in the range of 53% to 57% for the years 1996 through 2001 (T. 860) and that, based on 2005 SEC Form 10-K results, the debt to equity ratio of Entergy and its other operating companies were in the range of 51% to 53%, while EAI's was at 48%, clearly outside this Entergy operating company range. (T. 860)

Commercial Group witness Gregory recommends a capital structure of 48.33% long-term debt, 1.24% preferred stock and 50.43% common equity. (T. 590)

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[16]Docket No. 06-070-U, Oklahoma Gas and Electric and Docket No. 04-100-U, Empire District Electric Company.

In response to Staff's recommendation, EAI witness Lewis testifies that Staff's recommended debt to equity ratio would not meet Standard and Poor's ("S&P") Benchmarks for maintaining a BBB bond rating. (T. 215-216) Mr. Lewis calculated the impact of Staff's recommendation on three S&P ratios: (1) Funds from Operations ("FFO") to debt; (2) FFO to interest; and (3) debt to total capital, and testified that by adopting Staff's recommendation, these three ratios for EAI would be significantly and negatively impacted. Mr. Lewis states that this would have a detrimental effect on EAI's credit quality. (T. 216-217, 225-226) Further, EAI's witnesses argue that Ms. Gray's debt ratio calculations fail to utilize off-balance sheet obligations such as operating leases and post-retirement benefit obligations in her calculations of debt to equity ratios. (T. Ex. 51 and T. 263) Mr. Lewis also asserts that the negative outlook for Entergy Corp.'s credit rating is partially attributable to concerns about Arkansas regulatory climate. (T. 226)

EAI witnesses Lewis and Fetter contend that the adoption of Ms. Gray's hypothetical capital structure could lead to credit rating downgrades and higher interest costs over time. They also contend that such credit rating downgrades could result in EAI having to put up cash as collateral in various contracts as well as limiting access to capital markets, and that all of these results would be detrimental to EAI's customers. (T. 219, 266-267) In addition, EAI witness McDonald states there could be less capital investment by EAI and lower quality of service if Staff's proposed debt to equity ratio is adopted. (T. 126) However, during the hearing, Mr. McDonald, in response to questions from Staff Attorney Boyce, stated that EAI's commitment to reliable service quality will not diminish. (T. 198)

Mr. Fetter also asserts that adoption of Ms. Gray's recommendations on the cost of equity and debt to equity ratios would be perceived negatively by Fitch and Moody's in addition to S&P. (T. 269)

Ms. Gray responds to Entergy's bond downgrade assertions and provides calculations of various financial ratios for EAI using her recommended debt to equity ratio and cost of equity. She explains that her calculated FFO to interest ratio of 5.3 for EAI exceeds the S&P benchmark of 2.3 to 3.8 for EAI. She also explains that her calculation of the FFO to total debt ratio is 27%, which exceeds the S&P benchmark of 15% to 22%. Ms. Gray states that, utilizing her recommendation for the debt to equity ratio, total debt to total capital is 52%, which is within the S&P benchmark range of 50% to 60%. (T. 848, T. Ex. 410-411) She testifies that, even considering S&P's imputation of debt related to retirement obligations, her recommendations remain in the benchmark ranges for EAI. (T. 855, T. Ex. 412-413) Ms. Gray also states that imputation of debt could be significantly reduced because of Company witness Wright's statement that: "The Company actually paid over $80 million in July and September 2006 to reduce [the unfunded pension] liability" and that the actual September balance "is a debit of $24.6 million." (T. 852)

During the hearing, EAI witness Lewis agreed that using Ms. Gray's calculations, which include all aspects of Staff's cost of capital recommendations, would result in all of these ratios falling within S&P's benchmarks for BBB ratings. (T. 231)

Ms. Gray notes that the "negative" S&P outlook to which Mr. Lewis and Mr. Fetter refer is applicable to Entergy Corp. and each of its operating companies and reflects, among others, two factors unrelated to EAI's regulated operations: (1)

regulatory challenges relating to the separation of Entergy Gulf States into two companies; and (2) increasing exposure of non-regulated operations. (T. 854-855) Ms. Gray also explains that the Fitch credit report to which Mr. Fetter refers states that "on a stand-alone basis...the company's ratings are constrained by the linkage to its parent, Entergy Corp." Ms. Gray points out that EAI ratepayers should pay rates on a less leveraged capital structure when the rating of the parent is a limitation on the Company. (T. 855, T. Ex. 2)

Ms. Gray also testifies that over 40% of the Company's revenues (exclusive of decommissioning) are subject to adjustments outside the context of a general rate proceeding. She states that since S&P generally views non-rate case recovery mechanisms as positive, Staff's overall recommendations in this case should not be considered detrimental by S&P but should decrease uncertainty and have a positive impact.[17] (T. 856)

In response to EAI witness Fetter, Ms. Gray notes that the Moody's report reflects a stable, not negative, outlook for EAI and that Staff's recommendations are consistent with Moody's expectations. (T. 856)

EAI witness Wright presents a calculation based on Ms. Gray's recommended capital structure blended with EAI's actual capital structure to produce an 8.9% allowed

[17]The Commission takes administrative notice of the fact that over the past twelve months Entergy's common stock has risen from the mid-60's to a recent stock price of approximately $110 per share. This represents a price run-up of approximately 65% on an annual basis. Further, during the past twelve months Entergy's common stock price has achieved a high of $120 per share. (See financial information reported by Value Line and the Arkansas Democrat Gazette Newspaper.) Further, Standard & Poors recently affirmed its BBB corporate credit rating for Entergy Corp and its subsidiary operating companies including EAI. In addition the outlook on Entergy and its subsidiaries was revised to stable from negative. Regarding EAI's pending rate increase application Standard & Poors reports that it views the recovery by EAI of FERC allocated production cost payments as "important for EAI. Nevertheless, the overall effect should be neutral for Entergy's consolidated financial profile. (See Standard & Poors Research Update dated June 4, 2007.)

return on equity. (T. 537-538, T. Ex. 187) Ms. Gray agrees with EAI witness Wright's calculation and states that is the intended purpose of her adjustment. She explains that ratepayers should not be required to pay rates based on excessive levels of equity in the capital structure, and that if EAI chooses not to adjust its actual capital structure; the observation that 9.9% may not be achieved is irrelevant for purposes of determining the appropriateness of an adjustment. (T. 863) We agree.

The Commission finds that Ms. Gray's recommended debt to equity ratio is appropriate. It is consistent with the debt to equity ratios resulting from her risk-comparable and industry samples. It is also consistent with the debt to equity ratio of Entergy Corp. for the four quarters ending September 30, 2006 and the parent-only amount of debt that EAI's parent uses for its investment in EAI. Staff's recommendation is also consistent with the total debt to total capital ratios for EAI for the years 1996 through 2001; the consolidated parent's, Entergy Corp., total debt to total capital ratios for the years 1996 through 2001; the current debt to equity ratio of Entergy and its other operating companies; and maintenance of EAI's current bond ratings.

In this finding, the Commission also emphasizes three important considerations. First, it is important that there be congruence between the estimated cost of equity and debt to equity ratio. A lower debt to equity ratio decreases financial risk and, other things being equal, decreases the cost of equity. EAI failed to make that connection. Conversely, a higher debt to equity ratio increases financial risk and, other things being equal, increases the cost of equity. Ms. Gray's analysis accomplishes that congruence since her recommendations on both cost of equity and debt to equity ratio utilize her risk-comparable samples.

Although the phrase "hypothetical capital structure" is often used, sometimes it may be appropriate to refer to it as an "optimal capital structure." Given the correlation between debt to equity ratios and the cost of equity, it can be demonstrated that there is just one capital structure, the optimal capital structure, which minimizes the overall cost of capital. It is reasonable to assume that a risk-comparable sample should reflect "best practices" in a financial sense. Those "best practices" will encompass the "optimal capital structure" for the risk-comparable sample. By relying upon a risk-comparable sample to determine the debt to equity ratio, it can be fairly asserted that that is also the "optimal capital structure" for the utility in question.

Finally, this Commission is not necessarily recommending that the Company change its current debt to equity ratio to be consistent with Staff witness Gray's recommended hypothetical or optimum debt to equity ratio. That is the Company's decision to make. Ms. Gray's debt to equity ratio is an "adjustment" like other accounting adjustments that the Commission routinely makes. When the Commission disallows certain items from rate recovery we are not requiring the utility to cease making such expenditures. The Commission's responsibility is to determine which expenses are reasonable and necessary for the provision of utility service to ratepayers. The Commission's adjustment for the debt to equity ratio is similar: this is a determination regarding the appropriate ratio for ratemaking purposes.

Given our findings of a 9.9% allowed return on equity and our determination of the other capital component proportions and costs, the appropriate capital structure applicable to this case is that shown in Staff witness Gray's Surrebuttal Exhibit-30. (T. Ex. 400)

Entergy System Money Pool Lending

The Entergy System Money Pool is an internal financing mechanism whereby the Entergy Operating Companies ("EOCs") make short-term loans to each other depending upon their daily, weekly, and monthly needs.

Staff witness Gray recommends that an adjustment be made to EAI's capital structure to reflect the net lending by EAI to the Entergy System Money Pool. Ms. Gray explains that it is not clear that EAI ratepayers benefit from EAI's net lending position, and she adjusts $32,003,676 proportionally from externally-supplied funds (long-term debt, preferred stock, and common equity). The fact that EAI is a net lender to the other EOCs implies that EAI has incurred unnecessary additional sources of external financing (stock, debt, etc.) in order to make those loans to the other EOCs. EAI's ratepayers do not benefit from those loans; and yet they pay higher capital costs of external sources because of the loans. Consequently, it is appropriate that the amount of those loans be adjusted out of the externally-supplied funds. Although this amount has increased by an additional $14 million as of February 2007, Ms. Gray did not have this information in time to be included in her surrebuttal rate of return recommendation. (T. 821, 872; T. Ex. 373-374, 407-408)

EAI witness Wright contends that, given the significant disparity between Staff's and the Company's recommended common equity ratios, EAI will not have a material amount of cash available for investment in the money pool. Mr. Wright notes that any excess cash would presumably be used to make dividend payments in order to decrease the common equity ratio. (T. 536)

Ms. Gray responds that in the years 2002-2005, EAI could have issued additional amounts of first mortgage bonds to maintain a total debt to total capital ratio within the appropriate benchmark range. Ms. Gray notes that EAI could reasonably use debt financing in the future. (T. 871-873)

The Commission finds that Ms. Gray's money pool adjustment is appropriate. It is unacceptable for EAI's ratepayers to pay the relatively high costs associated with $32 million in outside capital in order to loan money to the other EOC at lower interest rates, and it is a direct subsidy of those other EOC's ratepayers by EAI ratepayers. This problem is particularly egregious at this particular time when EAI's ratepayers will be significantly subsidizing the other EOCs because of the FERC-mandated bandwidth remedy. Any additional subsidies from EAI to the other EOCs would only worsen a situation already unreasonable.

Current, Accrued and Other Liability ("CAOL") Zero Cost Funds

Accrued Interest Payable

EAI witness Wright and Staff witness Walker each included Accrued Interest Payable as part of zero cost funds. (T. 515, 1311) Accrued interest payable reflects the fact that the Company receives customer payments for interest on debt on a daily basis and prior to the time when the Company must make explicit interest payments to the bondholders. During that period of time the Company has interest-free use of the money provided by ratepayers, and it should be considered a zero-cost source of capital.

EAI witness Wright recommends that the Commission include the 13-month average of accrued interest payable in the capital structure. (T. 514-515) Staff witness Walker calculated his balance for this account using current debt cost and debt levels

reflected in Staff's proposed capital structure. (T. 1311) The Commission adopts the Staff's approach, which uses updated debt outstanding and respective interest rate information consistent with Staff's surrebuttal capital structure recommendation. With the adoption, as discussed elsewhere in this Order, of Staff's capital structure recommendation, it is appropriate to use the pro forma interest data that is consistent with that capital structure.

Dividends Payable

No party disputed the inclusion of dividends payable in the MBSA. However, EAI disputes the calculation of the common dividend lag calculated by Staff witness Walker. Mr. Walker calculated the lag based on the declaration and payment dates made by Entergy Corp. to its investors. (T. 1299, 1311) EAI witness Wright asserts that the lag should be based on the declaration and payment dates made by EAI to its parent, Entergy Corp. (T. 514)

The Commission adopts Staff witness Walker's method for calculating the common dividend lag. The purpose of the inclusion of dividends payable in CAOL is that investors in Entergy stock recognize that there is a lag between the time that Entergy's dividends are declared and the time when dividends are actually paid. Because of this lag, and to compensate for the time value of money, investors require a slightly higher return on equity. Any cost of equity methodology that is market-based, such as the DCF method, will already include that effect in the estimated cost of equity. In this case we are estimating Entergy Corp.'s cost of equity, and using that as a surrogate for EAI's cost of equity since EAI has no market-traded common stock.

Consequently, to match the estimated cost of equity with the calculation of dividends payable it is appropriate to use the dividend payment lag of Entergy Corp.

Unfunded Pension Liability

EAI witness Wright includes in his calculation of CAOL a debit balance of $17.396 million in its accrual liability account, Unfunded Pension Expense,[18] representing the 13-month end average in that account, ending June 2007. (T. 1307) Staff witness Walker proposes that a credit balance of $30.086 million, representing the 13-month end average for that account, ending December 2006, be included for purposes of measuring the available cost-free funds for Unfunded Pensions. (T. 1307)

Mr. Walker contends that the debit balance requested by EAI is not representative of the normal level for that account, and that, based on the account's recent historical activity, the account normally carries a credit balance rather than a debit balance, and that his credit balance of $ 30.086 million is more indicative of that normal balance. (T. 1307) Mr. Walker explains that, from 2002 through year-end 2005, by making no payments into the account, EAI allowed the credit balance to increase by over 350%, from a credit balance of $20.1 million to one of $70.3 million. Mr. Walker notes that, primarily within the pro forma year, EAI made payments to that account which resulted in the $17.396 excess, which he asserts does not reflect a representative balance for that account. (T. 1308)

EAI witness Wright contends in his Rebuttal testimony that, assuming a Pension Expense and corresponding accrual of $23.2 million per year, it would take some 2 to 3

[18]Accruals are credited to this account each month, based on actuarial reports related to pensions, with the corresponding monthly debit made to Pension Expense. Payments for these Unfunded Pensions are then debited to the liability account when made, with the balance in Unfunded Pensions normally reflective of a credit balance. (T. 1307)

The Commission disagrees with Mr. Wright. The concept of normalization in ratemaking is not applicable only to expenses. [19] As a general rule, all components used to calculate rates should reflect the expected, normal level[20] of that component - a policy the Commission has consistently applied in its rate orders. With regard to measurement of working capital needs under the MBSA, the balances used should reflect the daily average expected balances of those accounts.

The record is clear. Staff witness Walker reviewed the account activity over a period of several years. The result is that his recommended $30.1 million credit balance approximates the actual average balance in that liability account over the last five years. (T. 1308-1309) The Commission also finds that EAI witness Wright provides no evidence to support a finding that Mr. Walker's recommended level, which was based on historical balances, is not reflective of the average, normal level expected for this account. Mr. Wright also does not assert that his recommendation of a $17.4 million debit balance for this account is indicative of expected normal daily levels. Mr. Wright does not dispute that, although recovering the expense for the entire period, EAI did not, for several years, make payments to reduce its corresponding Unfunded Liability, with that inaction resulting in the substantial annual growth of the liability - some $70 million by 2005. (T. 1308) Mr. Wright also acknowledges that EAI made large payments against this liability within the months immediately prior to and after the

[19]The Commission notes that EAI proposes a weather adjustment be applied to its billing determinants in this case. A weather adjustment removes any "abnormal" usage related to "abnormal" weather.

[20]The Commission would also like to point out that "normal" does not always mean "average". If it is reasonably known and measurable within the pro forma year that any rate base, income, expense, or capital structure account will prospectively and consistently reflect a higher or lower balance than that reflected in the test year, whether based on specific changes or based on historical trend analysis, such amount would be recognized, where appropriate, as the 'normal' level of that account for rate purposes.

years before EAI would reach the credit balance of $49 million Staff had originally included as part of CAOL in Direct testimony and, thus, Staff witness Walker's balance will not be representative of this account when rates become effective. (T. 512-513, 1308) Responding to Mr. Wright's contention, Mr. Walker testifies that, Staff's currently proposed $30.086 million balance approximates the actual 5-year average, or midpoint, balance in that account. Thus, assuming a 5-year interval between rate filings, on average, EAI will recover all of its costs. Further, Mr. Walker notes that, should EAI duplicate its 10-year interval between its most current rate filings, EAI could actually collect more than that balance over the additional 5 years. (T. 1309)

In response, EAI witness Wright testifies that "Walker's approach would normalize a balance sheet account the same way you would normalize an expense account...(but) (t)he concept is not the same." (T. 561-J) Mr. Wright contends that "(w)e are looking to establish rate levels that take effect in mid-2007 to reflect costs that will exist in mid-2007...," (T. 561-J) so that, even assuming no additional payments, the projected 13-month average for this account through end of the pro forma year would be a debit balance of $2.1 million. That average balance, Wright further contends, is "surely the highest level at which this expense could logically be set for the purposes of establishing rates under any set of reasoning...." Mr. Wright states, that, however, "(t)o reflect reality, the Company recommends an average amount of (a debit balance) of ($17.4) million...to account for the contributions actually made in July and September." (T. 561-I – 561-J)

filing of its current rate case, actually over-paying the liability, the result of which is the basis for the $17.4 million average debit balance EAI asks be used to offset its zero cost funds. (T. 512) Finally, Mr. Wright acknowledges that, although EAI recognizes some $23.2 million of Pension Expense in its current requested rate, EAI will, in the future, again withhold payments to fund Pension Expense and allow the credit balance in this liability account to increase. (T. 561-J)

The use of an expected, normal balance for this account neither disadvantages EAI nor thwarts EAI's opportunity to earn a fair return as Mr. Wright implies.[21] Staff witness Walker correctly points out that, assuming EAI rate filings are made on the average[22] of every five years, his recommendation for the Unfunded Pensions Expense balance will provide EAI the opportunity to recover its actual cost over that next five years. (T. 1308-1309)

EAI's proposal to include an aberrant debit balance in its liability account, Unfunded Pensions Expense, does not reflect appropriate ratemaking treatment. The proposal is therefore rejected. The Commission finds that Staff's recommended $30.1 million balance for Unfunded Pension Expenses is representative of the expected, average, and normal level for this account and is consistent with the corresponding Pension Expense recommended by both EAI and Staff. Therefore, the Commission approves $30.1 million for Unfunded Pension Expenses.

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[21]Mr. Wright testifies that "the Company will not have the CAOL liability for unfunded pension expense proposed by Mr. Walker at the time rates go into effect and will not for at least two years." (T. 561-K)

[22]Averaging costs over expected periods between a utility's rate case filings is a standard and accepted method in measuring costs to be used to set prospective rates and does not constitute a form of "single-issue" ratemaking. (T. 1342-1344)

Storm Damage Reserve Account / Storm Damage Expense

EAI witness Wright includes, in his calculation of CAOL, an average debit balance of $46,585,000 for the liability account, Storm Reserve. (T. 1299) Mr. Wright recommends that this debit balance be used to offset CAOL or, alternatively, be included in rate base for a return. (T. 513) Mr. Wright argues that these costs are appropriately booked using "reserve accounting." According to Mr. Wright, under that accounting treatment, this liability account and its related expense, Storm Damage Expense, should, for ratemaking purposes, be treated differently than other Operations and Maintenance ("O&M") items which do not use reserve accounting. Mr. Wright testifies that, in reserve accounting, "the storm accrual approved in rates" is debited to Storm Damage Expense and credited to the Storm Reserve. When actual storm damage costs are incurred, they are debited against the accrued credit balance. (T. 502-503) According to Mr. Wright, for ratemaking purposes, any debit balance[23] in the account should either be added to rate base or be used to reduce CAOL. Additionally, Mr. Wright testified that an amortization of that debit balance, representing unrecovered costs, should also be added to the current storm accrual and recovered prospectively from ratepayers. Conversely, Mr. Wright asserts, any credit balance in the Reserve account would be included as an increase to CAOL for rate purposes. (T. 502-503)

Mr. Wright also recommends that the Reserve's related Storm Damage Expense be set at $29,720,000 for the pro forma year. (T. 508, 561-F) Mr. Wright testifies that the $29.7 million is based on three elements: (1) a proposed 5-year amortization of the Reserve's almost $50 million in prior period costs, or $9,854,000 per year (T. 508, 1310,

[23]The debit balance in the Storm Accrual Account represents storm costs incurred which were in excess of the annual expense accruals allowed in EAI's last approved rates.

1475); (2) $14,449,000 in the expected, normalized level of Storm Damage annual expense, the amount of which is not in dispute (T. 508, 1475); and, an extra "$5,417,00 for a 30-year amortization of the 2000 ice storm costs to build a reserve balance." (T. 508)

In support of this treatment, Mr. Wright testifies that "(t)he use of reserve accounting for storm costs is appropriate because of the nature of storm costs... (given that)... (t)he severity and number of storms are clearly out of the Company's control." (T. 503-504) Mr. Wright states that normalization[24] rather than the use of the reserve method "would improperly provide no recovery of previously incurred storm costs above the current level of accrual." (T. 504) Mr. Wright also advises that some 62% of these costs would be considered "production costs" in the calculation of payments required by the FERC in Opinions Nos. 480 and 480-A ("FERC Payment").[25] (T. 501) Finally, Mr. Wright testifies that, in EAI's last rate case, Docket No. 96-360-U, the Commission accepted the reserve method and used the then-credit balance in that account as an increase in the CAOL. (T. 561-C)

EAI witness McDonald also supports this rate treatment and urges the Commission to consider, from a public policy standpoint: (1) that service restoration is a health and safety issue as well as one of commerce, the disruption of which affects businesses, customers, and employees; (2) that, because Staff will thoroughly review any recovery request, EAI needs no other incentive to control costs; (3) that storm costs are

[24]Mr. Wright responds to Staff's recommendation to include only a normal, expected expense amount for Storm Damage cost. (T. 504)

[25]Pursuant to the System Agreement under which EAI operates with its affiliated utility Companies in Mississippi, Louisiana and Texas, FERC has proscribed a cost equalization formula, the results of which are that the higher the production cost experienced by each Entergy Operating Company, the lower its obligations to the other Entergy Operating Companies will be.

volatile and are caused by natural weather disasters, which are unusual and non-recurring events, and therefore are not comparable to other expenses; and (4) that the Commission should "encourage prompt action by utilities in emergency situations" by approving full recovery of these costs under reserve accounting. (T. 183)

Alternatively, Staff witness Walker, addressing the balance sheet's Reserve account, recommends elimination of the Reserve's debit balance from CAOL. Mr. Wright testifies that Staff has appropriately included a normalized level of these costs in Storm Damage expense and, therefore, there is no need to recognize the Reserve balance. (T. 1299) Staff witness Walker testifies that "EAI is not guaranteed 100% recovery of ... costs," and therefore it is not appropriate to allow rate treatment which would allow EAI to "retroactively recover these (past) costs both through a five-year amortization in expense and by either reducing the CAOL balances included in the capital structure or increasing the WCA balances in Rate Base." (T. 1310)

Staff witness Plunkett recommends approval of only the normal expected Storm Repair Expense of $14,449,000.[26] (T. 1470-1471) Ms. Plunkett recommends that the Commission reject both EAI's proposed amortization of past expense and its proposed accrual to build its reserve as not appropriate for rate purposes. Ms. Plunkett testifies that some $9 million or more of the request is for EAI's recovery of almost $50 million in prior period costs. Ms. Plunkett also testifies that EAI's request for $5.4 million annually to "build" reserves rests largely on the remote possibility that EAI will

[26] Ms. Plunkett calculated the normal, expected level of Storm Damage expense using a five-year historical average from which she had removed all abnormal storm costs, including those related to the 2000/2001 ice storms and Hurricanes Katrina and Rita. (T. 1470-1471)

experience two more "back to back hundred years storms."[27] (T. 1476-1479) Ms. Plunkett testifies that, notwithstanding EAI's use of reserve accounting or Storm Repair cost volatility, EAI provides no convincing reason to isolate and afford this one expense rate treatment that differs significantly from all other expenses. (T. 1476-1477) More appropriately, these costs should be included at a normal level which, witness Plunkett testifies, will provide EAI due incentive to control those costs in the future. (T. 1476)

AG witness Marcus recommends that the Commission allow annual recovery of $14.4 million in normalized expected expense but does not recommend approval of EAI's proposed $5.4 million accrual to build a reserve, citing concerns regarding both the propriety of allowing ratepayers to fund "additional" reserves as well as the timing of that additional ratepayer burden, given other cost increases expected for ratepayers. Mr. Marcus advises further that, although initially recommending EAI's proposed amortization of prior period costs as reduced for approximately $3.4 million in inappropriate charges, he no longer has a recommendation with regard to its inclusion in rates. (T. 752, 1273)

The Commission finds that EAI's proposed treatment of its Storm Reserve balances, if approved, would constitute retroactive ratemaking and, therefore, is rejected. The Commission makes this finding given both the almost $50 million[28] of admittedly prior period costs EAI accumulated in the Reserve account which it includes as a reduction to CAOL and its amortization of that same prior period cost as a current expense. (T. 1388-1389) The Commission also rejects EAI's proposed treatment for

[27]Ms. Plunkett notes that this is the description provided by EAI's current witness McDonald for the ice storms of 2000-2001 in his testimony in Docket No.01-084-U-U. (T. 1479)

storm costs as single-issue ratemaking and agrees with Staff witnesses Hilton and Walker that it is inappropriate to isolate only one component of revenue requirement for year to year measurement and to ignore the changes in all other components. (T.1391, 2209-2210) The Commission also finds EAI's proposed isolated rate treatment of this one element inconsistent with its own testimony. EAI witness McDonald, when asked about EAI's significant sales and revenue increases over the same period EAI accumulated its 'excess' Storm costs, responded that it is inappropriate to isolate the import of that growth to "just one component of the business," (T. 1553-1544) at the same time he requests isolated rate treatment for the same "one component of the business".

The Commission rejects EAI's proposed rate treatment for both the Reserve for Storm Damage and Storm Damage Expense and adopts Staff's recommendations. The Commission finds that Staff's recommendation appropriately includes a normal, expected annual level of Storm Damage costs of $14.449 million, the amount of which is not in dispute. (T. 1380-1388, 1470-1471) The Commission also finds that Staff's recommendation to reduce the related Reserve to zero is consistent with the averaging method Staff used in determining a normal expense level and will result in the Reserve reflecting, on average, a zero balance.

Transmission Reserve

EAI witness Wright testifies that Staff witness Walker incorrectly included a liability, Transmission Reserve, in Staff's proposed zero cost funds. As a reserve account, the Transmission Reserve is established when its related expected transmission

[28]Mr. Wright has included in CAOL a thirteen month-end debit balance for the Reserve Account in the amount of $46,585,000 which captures the amount EAI requests be amortized. (T. 513)

expense is recognized prior to actual expenditures, with actual expenditures used to offset the reserve when made. Mr. Wright testifies that Mr. Walker's inclusion of this liability is inappropriate because Staff witness Plunkett excluded the Transmission Reserve's related expense, resulting in "no cash flow impact for this accrual." Mr. Walker testifies, however, that Staff witness Davis made an offsetting adjustment to Ms. Plunkett's, adding back the corresponding expense. Mr. Walker further testifies that, in addition, he found that the Transmission Reserve account remains a liability on EAI's records as of December 31, 2006, and, consequently, that liability should remain in the calculation of EAI's zero cost funds. (T. 1312) Rebutting Mr. Walker, EAI witness Wright further testifies that Staff witness Davis' addition, although close in amount, was unrelated to Staff witness Plunkett's eliminated account, that the expense Ms. Davis included is not being accrued to the Transmission Reserve account, and, therefore, the Transmission Reserve should be eliminated. (T. 561-L) Staff witness Walker, however, explains that, in fact, Ms. Davis' addition to the transmission expense account was a replacement for the same costs removed by Ms. Plunkett, that it approximated the amount remaining on EAI's books, and, thus, Mr. Walker appropriately included the Transmission Reserve liability in his zero cost calculation. (T. 1360-1363)

The Commission finds that the reserve-related transmission expense has been accounted for by Staff, that the current per book information as of December 31, 2006, indicates there remains a balance in the Transmission Reserve, and although given ample opportunity to do so, EAI provides no exhibit or other substantive evidence to support its position that this per book liability should be removed from consideration as

a zero cost element. Therefore, the Commission finds that Staff's inclusion of its calculated balance as a zero cost component is appropriate.

Rate Base

Plant

Plant Additions and Expenses Related to Broadband Equipment

Staff witness Davis testifies that EAI has increased its test year plant and expenses to recognize its expenditures for its Broadband Over Power Lines ("BPL") pilot program, adding more than $300,000 to rate base and $90,000 in expense. Ms. Davis testifies that, although expected to be operational by June 2007, EAI fails to provide sufficient evidence to verify the expected in-service date and recommends that the Commission disallow the BPL program costs, finding it premature for ratepayers to pay these costs during the evaluation stage. (T. 2067-2068) In addition, Ms. Davis testifies she is not making any finding as to the merits of the BPL pilot program, but is basing her recommendation on the uncertainty surrounding the in-service date of the program and the lack of evidence provided by EAI showing that it will benefit ratepayers. (T. 2072-2073) AEEC witness Falkenberg expresses concerns regarding the cost effectiveness of the program and its application for non-utility uses. AG witness Marcus suggests that it is more appropriate to address the implications of this type of pilot program in a separate docket outside of a general rate case. Both witnesses recommend that the Commission not approve such costs at this time. (T. 705-706, 1865)

EAI witness Castleberry testifies that its current BPL pilot program has reflected potential utility-related benefits in carrying data over power lines, including "remote metering, remotely connecting and disconnecting power at the customer premises, and enabling security cameras through the power line." He further asserts that the BPL pilot

program is used and useful as a pilot which is currently operational and being tested in two separate locations. He testifies that its continuation will allow the testing of technology that "has the potential to improve electric reliability, reduce outage response times, and reduce operational costs." (T. 1614-1615)

The Commission finds that the potential utility reliability and cost benefits for ratepayers justify current rate treatment of EAI's BPL pilot program. The Commission notes that this technology may provide a means by which programs such as the Irrigation Switch Program and other demand response programs may be successfully offered, helping to reduce peak load, and to reduce overall capacity costs. (T. 1603-1604) However, the Commission appreciates the concerns expressed by the other parties in this docket regarding the potential non-utility application of the technology and potential ratepayer subsidy current ratepayer funding may provide. Although approving the BPL investment and related expenses in this case, the Commission reserves judgment regarding the future assignment of costs of implementation of the BPL program to ratepayers and the sharing of these technologies with non-utility functions, including appropriate pricing to those functions in the context of any future rate determination and under the Commission's Affiliate Transaction Rules.

Pro Forma Plant Levels

Staff witness Marshall testifies that, based on information provided by EAI, she has adjusted her proposed levels of pro forma plant to add certain plant as recommended by EAI and made certain mathematical corrections. (T. 1432-1434) With these changes, there are no outstanding issues among the parties related to the level of plant to be included in rate base. For simplicity, the Commission, therefore, adopts

Staff's most current recommendation for plant to be included in rate base, except that the Commission approves EAI's inclusion of broadband equipment.

Accumulated Depreciation/Depreciation Expense

Blytheville Turbine Removal Costs

Staff witness Marshall testifies that EAI has held $18,236,966 in costs it incurred in 2001 for refurbishing its Blytheville turbine and now seeks to transfer that full debit balance to the Accumulated Depreciation account, labeling it a cost of removal and thereby increasing rate base. Witness Marshall testifies that, as indicated in protected information supplied by EAI, the adjustment made by EAI is not appropriate, and recommends the Commission disallow this $18 million increase to plant. (T. 1424) Staff witness Plunkett testifies that, in addition to rate base treatment, EAI also requests current recovery of those costs in the amount of $3,647,393 annually, assuming a five year amortization, and she recommends that this amortization also be disallowed. (T. 1469)

In support of both the rate base and expense treatment, EAI witness Wright testifies that these costs were accounted for pursuant to appropriate accounting standards when EAI capitalized and posted them to accumulated depreciation for current rate treatment as an amortization. (T. 529-530) Further he states that Staff did not challenge the capitalization treatment of these costs during its audit of EAI's previously effective Regulatory Earnings Review Tariff, ("RERT") in the year in which they were incurred and therefore these costs should be included both in rate base and as an expense at this time. (T. 529-530, 532, 561-O) Mr. Wright testifies that Staff has not asserted and does not now assert that these costs are not legitimate, reasonable, and

recoverable (T. 529), irrespective of when they were incurred (T. 530) or whether the facility's now discontinued lease payments are still reflected in current rates. (T. 561-P) He also asserts that this filing is EAI's first opportunity to request amortization of the capitalized cost. (T. 530) Mr. Wright recommends that the Commission allow "the recovery of this prudently incurred cost, and the cost should remain in rate base as it has been in previous earnings reviews." (T. 532)

In her Protected Surrebuttal Testimony[29] Staff witness Marshall describes the character or nature of the Blytheville turbine removal costs. With witness Plunkett's support, Ms. Marshall testifies that these costs were current charges when incurred in 2001 and are, therefore, out of period, non-recurring charges which should be removed from rate base with no related amortization allowed in current rates. (T. 1424, 1442, 1469, 1480) We agree with Ms. Marshall's description of those costs and with her conclusion regarding the appropriate ratemaking treatment for these costs.

The Commission finds that the record does not support EAI's proposal to include these 2001 lease-related costs in rate base nor does it support allowing the amortization of these costs in expense. Such costs are both non-recurring and clearly out of period and, based on the description provided by Ms. Marshall, are more appropriately deemed to be expense and, thus, should have been recognized in the year incurred. The Commission also finds that recognition in current rates of these six year old costs would constitute retroactive ratemaking[30].

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[29]Marshall Protected Surrebuttal Testimony at page 7, lines 13-14. (T. 1453)

[30]The Commission notes again inconsistent treatment proposed by EAI. Mr. Wright recommends a capturing of these 6 year old Blytheville costs for current accrual, asserting that this is EAI's first opportunity to seek recovery. (T.530) However, Mr. Wright does not similarly propose that the Commission capture and accrue EAI's cost reductions related to the cessation of the Blytheville lease. Mr.

The Commission also rejects Mr. Wright's inference that Staff's lack of objection to capitalization of this expense in EAI's RERT filing provides assurance of future Commission approval of prospective rate treatment in a general rate case. (T. 561-O) The Commission finds, rather, that it was EAI's choice to capitalize these costs in its RERT filing, although it had originally accounted for such costs as an expense. (T. 561-O) If EAI had wanted Commission approval of these costs as an expense under its RERT in the year incurred or if it had wanted Commission approval at that time to create a regulatory asset for future recovery, EAI could and should have petitioned the Commission for that rate treatment. EAI chose not to do so. The Commission finds no evidence to sustain EAI's contention that it had received approval for the inappropriate rate treatment it now seeks. Accordingly, recovery of the Blytheville turbine removal costs are denied.

Union Power Partners LP - FERC Order

EAI witness Wright, responding to adjustments made by Staff witness Marshall, testifies that, pursuant to FERC Order in Docket No. EL05-1-000, EAI must refund by the end of the year certain credits previously recognized as a Contribution in Aid of Construction ("CIAC"). The result of that refund, he states, will be to increase overall plant by $6.9 million and increase Depreciation Expense by $101,466. (T. 542)

Wright dismisses the fact that the Blytheville Plant lease and maintenance and tax expenses costs, which are fully recognized in EAI's currently effective rates, ended for EAI in 1998 with the lease termination. (T. 1441-1442) Instead, Mr. Wright appears to recognize that such treatment of past cost reductions would be retroactive ratemaking and that irrespective of the fact that current revenues were designed to collect costs no longer being incurred, "it is the normal result of the ratemaking process that such recovery would continue." (T. 561-P) Mr. Wright appears to conclude, correctly, that capture of these heretofore unrecognized past savings for prospective rate treatment is inappropriate retroactive ratemaking. Had Mr. Wright been consistent, he would have similarly concluded that capture of the heretofore unrecognized past Blytheville costs for prospective rate treatment is also inappropriate retroactive ratemaking.

Ms. Marshall testifies that she has now incorporated that refund into her Plant balance and has adjusted her depreciation accrual and expense appropriately, but also notes that, as reflected on Mr. Wright's Exhibit JDW-10, he has applied incorrect depreciation rates in his calculation and, thus, her recommendation in this regard differs from that of EAI. She notes that the rates for these accounts were approved in EAI's last rate filing in Docket No. 96-360-U. (T. 1443)

Therefore, the Commission finds that Ms. Marshall's calculation appropriately incorporates the current, Commission approved depreciation rates while Mr. Wright's does not. The Commission adopts Ms. Marshall's calculation.

Depreciation Expense
Compliance with Ark. Code Ann. § 23-2-304(a)(8)(C) and General Plant

Staff witness Gray, referring to the findings of Staff witness Marshall, testifies that EAI has failed to file for approval of depreciation rates related to two accounts, 320.2, Land and Land Rights/Nuclear Production Plant and 330.2, Land and Land Rights/Hydraulic Production Plant. She notes that, for purposes of the revenue requirement in this case, Staff has accepted the rates which EAI has employed. However, Ms. Gray recommends that the Commission direct EAI to "prospectively comply with the provisions of Ark. Code Ann. § 23-2-304(a)(8)(C)", by seeking approval from the Commission for the change or addition of any new rates, and filing, if necessary a request for approval of interim rates. (T. 885-886)

Ms. Gray also notes that EAI appears to have adopted amortization accounting for its General Plant accounts and, although Staff has accepted the results for purposes of the revenue requirement within this Docket, Ms. Gray recommends that the

Commission direct EAI to file, with any new rate application, a fully substantiated and supported request for that change. (T. 886-887)

EAI witness Wright disputes Ms. Gray's contention that EAI employs amortization accounting, stating that EAI accounts for General Plant equipment by schedule "in accordance with the Uniform System of Accounts 18CFR Ch.1 Electric Plant Instruction 10, Additions and Retirements of Electric Plant paragraph B(2)..." and that "(t)his is a ministerial matter and not an issue that requires APSC approval or action. (T. 561-L) Further, he testifies, EAI continues to apply the General Plant rates approved in its last rate case. (T. 1223)

Ms. Gray, however, testifies that while EAI used the rates approved in the last docket, it was EAI's unilateral change to new retirement schedules, schedules based on asset lives other than those used in the currently approved rates, which in her "estimation (is) akin to amortization accounting." (T. 1223-1226)

The Commission finds Ms. Gray's explanation persuasive and directs EAI to seek, in its next rate filing, Commission approval pursuant to Ark. Code Ann. § 23-2-304(a)(8)(C) for any new rate or any change in rates it wishes to implement. The Commission further directs EAI to appropriately request approval between rate filings of an interim rate at any time that it adds plant which has no approved depreciation rate. As to EAI's change in its retirement schedule, the Commission finds that such a change constitutes a change which may result in amortization accounting and, therefore also directs EAI to address that issue fully in its next general rate filing.

Working Capital Assets for the Modified Balance Sheet Approach

It has been this Commission's practice to provide for the working capital needs of utilities in its calculation of revenue requirement. Various methods are used to measure those needs, ranging from the simple, such as inclusion of only a few, isolated short-term assets in rate base, to the complex, such as use of a fully developed lead-lag study ("LLS"). In this regard, the Commission has used the Modified Balance Sheet Approach ("MBSA"), either in the absence of a LLS or as a check of a LLS filed by a utility.[31] Simply stated, the MBSA includes all utility assets in rate base, the impact of which is to recognize the "lead" inherent in an asset, and, at the same time, includes, as a proportionate cost of capital, all liabilities in the return calculation, which effectively recognizes the "lag" inherent in a liability.

The MBSA recognizes three basic facts: (1) a utility has investments in assets other than plant which are necessary to provide utility service, and on which a return should be allowed; (2) a utility has sources of funds, other than equity and long-term debt, which should be included in the capital structure; and (3) all liabilities are fungible sources of funds that are used to fund each and every asset of the utility. A corollary of this third point is that zero-cost liabilities should be placed in the capital structure in calculating the utility's cost of capital.

The rationale for placing all liabilities in the capital structure with the MBSA is that all liabilities are sources of funds used to finance the assets of the Company. No distinction can be made as to which asset a liability is funding because the funds

[31]Order No. 7 of Docket No. 84-199-U.

provided by liabilities are fungible. Therefore, to determine the total cost of funds for the Company, the MBSA posits that we cannot ignore CAOL.

Coal Inventory

As noted by EAI witness Wright, EAI has adjusted its per book average daily balance for investment in Coal Inventory to reflect an annual average 43-day operational inventory, increasing the book balance by $5.76 million. Mr. Wright testifies that the current average investment reflected in its accounting records translates into a 30-day operational level only. (T 552) EAI witness Mohl testifies that the average 43-day operational level upon which witness Wright based EAI's working capital investment is a result of getting the average daily operational coal inventory using EAI's currently approved Coal Inventory Policy. (T. 1018-1019) Mr. Mohl also states that adopting the 43-day operational coal inventory does not mean that a full 43 days of inventory will be available each day, only that, on average, the inventory will reflect that level of supply. (T. 1023)

Staff has included, as discussed by Staff witness Walker, a 45-day burn inventory based on EAI's historical levels. Mr. Walker testifies that this level essentially reflects an operational "average burn" 45-day supply, rather than EAI's proposed 43-day "full burn" supply. (T. 1306, 1329-1330)

The Commission finds that, as requested by EAI, its working capital should reflect the average investment in its Coal Inventory resulting from its currently approved Inventory Policy, under the assumption that this level will be maintained prospectively, representing an average, normal level. The Commission, therefore, approves EAI's proposed balance in this regard. The Commission, however, also orders

EAI to maintain that average operational supply as indicated in its approved Inventory Policy. Any failing by EAI to maintain that average daily level, as required by its current coal Inventory Policy, will be deemed imprudent and in direct violation of Commission order.

Undistributed Stores Expense and Clearing Accounts

Staff witness Walker recommends the elimination of Undistributed Stores Expense and Other Clearing accounts from rate base. Mr. Walker explains that the amounts reflected in these accounts are temporary, more akin to Construction Work In Progress ("CWIP"), and will be assigned to plant as it is completed or to operating expenses as incurred. Witness Walker testifies that, because Staff has appropriately recognized through the end of the pro forma year all used and useful plant to which these costs are assigned and has also included the most currently known and measurable pro forma level of all expense to which these costs are assigned, it is not appropriate to include the temporary accounts in rate base. (T. 1304-1305, 1306)

EAI witness Wright recommends inclusion of these accounts in rate base. Mr. Wright testifies that certain charges are accumulated in a separate account and are applied to the appropriate plant or expense as they are incurred. According to Mr. Wright, this is a regular utility practice and results in an ongoing balance carried on the balance sheet that is not reflected in either plant or operations and maintenance expense and should be included for rate purposes. (T. 517-518) Mr. Wright notes that, in EAI's last rate case, Docket No. 96-360-U, Staff witness McDowell did not eliminate these balances and, therefore, concludes that Mr. Walker's adjustment is inconsistent with prior Commission practice. (T. 518)

Therefore, the Commission finds Staff's treatment of such accounts appropriate and consistent with recent Commission practice and adopts it here. The Commission finds that these costs, which pass through such temporary accounts, are fully and appropriately recognized either as part of rate base assigned to pro forma plant or in the pro forma expenses to which they are assigned. The Commission also finds that to also allow the balances reflected in these accounts to remain in rate base and earn a return would result in recognizing them for rate purposes twice.

Deferred Board of Directors' Benefits/Deferred Capacity Solicitation Costs

Staff witness Walker also recommends the elimination of deferred balances for Board of Directors' Benefits and Capacity Solicitation Costs. Mr. Walker testifies that, similar to clearing accounts, Staff has recognized the full pro forma level of the related expense and, therefore, the deferred balance should not be included in rate base. Mr. Walker also testifies that such treatment is consistent with past Commission findings and that the Commission has found that, while inclusion of the expense may be appropriate, the deferred balance would not be allowed in rate base for purposes of a return. (T. 1305, 1380-1381) EAI witness Wright asserts that each of the accounts reflect funds the Company must expend until such time that the expense is paid, thereby benefiting the ratepayer and should be included in rate base. (T. 510-511)

The Commission finds, as it did with regard to clearing accounts, Staff's treatment appropriate and consistent with prior Commission findings and agrees that, given that Staff has included a full, normal level of pro forma expense for the costs; the related deferred accounts should not be included in rate base to earn a return.

Non-Tax Expenses

Payroll Levels for Distribution and Transmission

Staff witness Hilton disagrees with EAI witnesses Wright and McDonald on appropriate payroll levels for the pro forma year. In calculating the expected pro forma payroll levels, Mr. Hilton testifies that he uses the most current information available. He further states that he initially used current payroll levels as of October 30, 2006, which reduced the per book payroll balances by $2,625,325. (T. 1499-1450) In his Surrebuttal Testimony, Mr. Hilton notes that he further updated his recommendation for payroll, which is now based on the number of employees as of January 2007, provided in data responses from EAI (T. 1511-1512), adding $308,098 to his original reduction to test year payroll of $2,625,325 (T. 1499-1450) for a total reduction of $2,933,423.

EAI witness Wright agrees with Mr. Hilton's payroll figures, except for Wright's proposed addition of 41 new personnel[32] to be hired for Distribution and 24 new personnel[33] to be hired for Transmission. Mr. Wright testifies that the addition of these employees would increase Mr. Hilton's recommended payroll expense by $3.602 million[34] on an Arkansas-only basis.[35] (T. 541) Mr. McDonald testifies that all distribution personnel and all but four transmission personnel have been hired by EAI, with all new personnel expected to be in place by the end of the pro forma year. (T.

[32]Mr. Wright testifies that EAI intends to hire 28 linemen, 5 meter service personnel, and 8 operations coordinators, for a total of $2.438 million. (T. 541)

[33]Mr. Wright testifies that EAI intends to hire 13 relay technicians, 9 substation repairmen and 2 operations coordinators, for a total of $1.164 million. (T. 541)

[34]The sum of the Distribution personnel cost of $2.438 million plus the transmission personnel cost of $1.164 million.

[35]Mr. Wright testifies that the increase for total company would be $4.044 million. (T. 542)

1548-1549, 1561) Mr. McDonald testifies that the Company appropriately planned for these additions and that "(i)t was determined that additional manpower was required to help ensure that (EAI) safely, effectively and efficiently provides reliable service to our customers." (T. 181)

Staff witness Hilton testifies that EAI failed to provide a total and balanced picture of personnel activity at EAI, providing information only on its new hires without providing the same information regarding transfers and terminations. (T. 2120) Mr. Hilton expresses concern that he only became aware of the unplanned payroll additions upon receipt of an addendum to EAI's updated response to an open data request. (T. 1510) He expresses concern that these positions bypassed normal budgetary and approval phases and that some of the hiring forms indicated that these positions were to be filled by relocated, not new, employees. (T. 1512) Mr. Hilton further expressed concern that EAI's data shows that, historically, overall payroll levels have changed little, with new positions being created and old positions being eliminated. And, he continues, even for EAI alone and ignoring inter-affiliate personnel transfers, "over the course of the test and pro forma year, there was a negative 39 employees that...when you look at the individual details, for that same period of time, there were 85 hires, 122 terminations, 19 transfers in and 21 transfers out. So certainly all things are going on at the same time and... (T. 2121)...thus, any revision to employee count should be done in the context of a full update, not an isolated adjustment." (T. 1511) Mr. Hilton acknowledges that he received EAI's response to his request for support for the new personnel on March 21, 2007, but also testifies that the response contained limited information and did not, as the data request asked, provide evidentiary support for the

new hires. (T. 1511-1512) Mr. Hilton testifies that he has not received a complete update on overall payroll changes since receiving EAI's January 2007 update on March 14, 2007. (T. 2124)

The Commission finds that Staff's position regarding the proposed additions to pro forma payroll is balanced and appropriate. Staff acknowledges that, if it had received EAI's updated response to Staff's data request for total company payroll data, and had, after review, found that the information verified the new positions as the only change, the Staff would have routinely included those updates in its recommendation. (T. 2125-2126) The Commission finds that it is incumbent upon the utility requesting a change in its rates to timely provide full and complete information upon request. EAI has submitted a pro forma adjustment reflecting an incomplete picture of its expected payroll activity, despite the request from Staff to provide a complete picture. EAI has had ample opportunity to update both its February and March payroll information and has chosen not to do so. The Commission therefore finds that the data needed to make a decision to include these positions, from the perspective of the overall pro forma payroll level that is known and measurable, is not in evidence. Rather, the Commission finds that the Staff's proposed level is fully supported by the evidence and provides the best known and measurable level of expected pro forma payroll. Therefore, the Commission adopts Staff's position on payroll.

Incentive Pay/Executive Perquisites

EAI proposes to include "$14,432,069 for incentive compensation in O&M expense...of which approximately $2.0 million was paid by EAI, $6.0 million by ESI, and $6.6 million by nuclear operations...." (T. 689) Staff witness Hilton, addressing these

incentive packages, explains that there are multiple compensation plans, some of which are tied to operational benchmarks with others tied to certain financial benchmarks. Mr. Hilton testifies that the plans which are "predominantly-financial" incentives will benefit both shareholders and ratepayers and, therefore, recommends that these costs be equally shared. Mr. Hilton explains that, for all Entergy companies, including EAI, all incentive plans are made up of performance measures, with at least 25% of any plan made up of the incentive measure called the Entergy Achievement Multiplier, or EAM.

Mr. Hilton explains that EAM "is a measure of Entergy Corporation's financial performance using earnings per share and operating cash flow." Because EAM is tied to financial performance and benefits both stockholder and ratepayer, Mr. Hilton recommends the Commission disallow 12.5 % of incentives for plans which tie 25% of goals to EAM, 25% of incentives for those which tie 50% of goals to EAM, and 50% of incentives for plans entirely tied to the EAI measure. Mr. Hilton further testifies that EAI also offers certain incentive stock options plans, with the criteria for those plans tied entirely to increased shareholder value and, thus, tied 100% to a financial performance measure. Mr. Hilton testifies that stock option incentive plans, which are tied entirely to financial performance, should also be shared equally between stockholders and ratepayers and, therefore, recommends the Commission disallow 50% of such costs. Mr. Hilton recommends a total disallowance of $4,928,926[36] in non-stock option incentives and $7,682,797 in stock options. (T. 1500)

[36]Mr. Hilton testified he corrected an error in his Direct testimony, in which he had erroneously included other personnel benefits to the incentive payments, thus reducing his originally recommended adjustment of $6,598,908 (T. 1500) by $$1,669,982 (T. 1510) to $4,928,926. (T. 1510)

AG witness Marcus testifies that he also measured these same incentives and recommends an equal sharing of costs for incentive plans which include some operational criteria for performance. Mr. Marcus asserts, and Mr. Hilton agrees (T. 1513), that "(a)s a general rule, it is not good public policy to include 100% of incentive payments in rates". Mr. Marcus states that, to allow 100% of these costs in rates cushions stockholders from the risk that the financial goals will not be met, noting that, should employees fail to meet the assigned goals and, thus, be paid no bonuses, 100% of those bonuses remain in rates, generating revenues which help offset any negative results of under-performance. Moreover, Mr. Marcus testifies that the benefits of good performance flow to shareholders in periods between rate case test years "... (with those) EAI bonuses, for Arkansas, heavily tied to the profitability of the parent company." (T. 691, footnote omitted) Mr. Marcus states that there are several general plans, some of which are tied to both financial performance and to operational performance and some tied entirely to financial performance. Mr. Marcus testifies that financial performance is a direct measure of shareholder value. Therefore, he recommends that for these plans the incentive payments be shared equally between ratepayer and shareholder. (T. 692) Mr. Marcus further testifies that Entergy also offers other compensation plans, including plans related to "restricted stock, stock options, and stock-based long-term incentive programs...(which)...are based entirely on stock price of the parent company." (T. 692) These plans, he states, are tied entirely to the financial performance and the stock price of EAI's parent, Entergy Corp. For these, Mr. Marcus recommends that the Commission disallow all of these costs as benefiting only shareholders. (T. 692) Mr.

Marcus therefore recommends that the Commission disallow $7,606,446 in the non-stock option incentives and $15,365,000 in stock option plans. (T. 692-693)

Mr. Marcus also recommends disallowances for certain perquisites provided EAI's Chief Executive Officer and the five top executives at Entergy Corp. which are allocated to EAI, including those for club dues, financial counseling, the corporate airplane, and a tax "gross-up".[37] Mr. Marcus testifies that these types of expenditures are unnecessary in light of salaries paid and should not be borne by ratepayers. (T. 693)

EAI witness Gardner recommends that the Commission allow all of the incentives because they are necessary to attract and retain professional and managerial employees in a competitive market. (T. 1660-1661) He notes that the level of compensation paid, including the incentives, are set at the 50th percentile of similarly situated companies (T. 1655-1656), and would, if not allowed, require increases in base salaries which do not provide employee performance incentive. (T. 1662) Mr. Gardner further testifies that strong leadership is needed not only for the company's financial success but also for its operational success. (T. 1663) Mr. Gardner concludes that the overall compensation packages at issue are consistent with market practice and that:

> These metrics include a combination of operational, customer service, financial, safety and individual performance measures to ensure an appropriate alignment between the customer, employee and shareholder. Thus, it is appropriate to include recovery of all costs related to these compensation programs... (and to eliminate any of them)...would place a disproportionate weight on the base salary component of the compensation package. (T. 1665-1666)

According to Mr. Gardner, by tying employee compensation to these financial incentives, EAI shares the risk of its financial success with its employees. If these

[37]Mr. Marcus explains that these are payments which effectively pay the employee the income tax impacts of compensation to that employee. (T. 693)

incentives are disallowed, EAI would be required to change its compensation approach, and its employees would no longer share that financial success risk. (T. 1666)

EAI witness McDonald testifies that Staff's and the AG's proposed disallowance appears to be based on the theory that employee incentives tied to stockholder benefit result in the "interests of shareholders and customers ... not (being) in alignment so customers should not pay for all of the cost of these programs." Mr. McDonald asserts that tying of compensation to Entergy corporate earnings and stock prices will encourage employees to increase efficiency and reduce costs, to the benefit of customers; thus, the interests of shareholders are not at odds with those of customers. (T. 153-154) Mr. McDonald testifies further that it is not reasonable to disallow these costs under a "false assumption" that they are not a "reasonable cost of utility operations." (T. 155)

Staff witness Hilton disagrees with Mr. McDonald's equating ratepayer interest with that of Entergy Corp. stockholder interest, acknowledging that cost savings may, to some extent, be shared by ratepayers, but cost cutting to increase financial value can also be at the expense of ratepayers, *e.g.*, reductions in maintenance and repair, which will eventually result in higher rates. (T. 1514) Mr. Hilton asserts that Mr. McDonald ignores this dichotomy of interest, which is why a sharing is appropriate. Mr. Hilton further notes that a rate increase itself is a direct benefit to stockholders at the direct expense of ratepayers, who, unlike customers in a competitive market, cannot simply take their business elsewhere. (T. 1514) Mr. Hilton also testifies that tying these incentives to the financial success of Entergy Corp. rather than the success of EAI increases the disconnect between the payment of the incentive and any EAI ratepayer benefit. Finally, Mr. Hilton testifies that Staff's recommendation is not to simply

disallow these costs, but rather "to encourage objectives which yield direct benefits to ratepayers." (T. 1515)

AG witness Marcus questions the validity of EAI witness Gardner's rationale for considering these incentives as simply the cost of doing business, noting that compensation programs tied to surveys of other companies' programs and as employed by EAI, will inevitably become circular and spiral upward. Mr. Marcus rebuts Mr. Gardner's assertions that these incentives, overall, are tied to a combination of factors, stating that several of the incentive packages are tied only to financial performance and all of them have some financial incentive attached. Mr. Marcus also testifies that, in a competitive market, competitive pressures do not automatically allow higher prices as a result of paying these large incentive packages. Because prices cannot be increased, commensurate cost cutting measures must be taken to accommodate the increased expense, including lay offs, outsourcing, or increased efficiency. Absent other expense reductions, the result will be reduced profits and disgruntled stockholders. In contrast, Mr. Marcus continues, for rate regulated firms, which include 100% of these costs in rates as the "cost of doing business", the ratepayer simply pays the increase, receiving no commensurate benefits from cost cutting or increased efficiency. (T. 758)

The Commission finds that, as both witnesses Hilton and Marcus testify, the incentives tied to <u>operating</u> performance do increase efficiency, safety, and reliability and provide direct benefits to ratepayers in the form of better and more reliable service and should be included in rates. The Commission further finds that the incentives tied to <u>financial</u> performance are clearly designed to directly, materially, and measurably

increase stockholder value, and provide ratepayer benefit, and should, thus, be shared with stockholders.

The Commission, however, does not find substantive evidence of any material benefit to ratepayers attributable to those programs strictly tied to the stock prices of Entergy Corp. Although EAI witnesses testify to some general benefits ratepayers may enjoy, EAI offers no substantial evidence of ratepayer benefit which would justify including these stock-driven incentives in rates.

The Commission finds that both Staff and the AG recommend some sharing of costs for those programs which contain general financial performance measures, including the Exempt Incentive Plan, Executive Annual Incentive Plan, Management Incentive Plan, and the Team Sharing Incentive Plant. (T. 689-690) The Commission, however, finds that, while the AG recommends a simple 50% sharing of the entire incentives paid under each of these programs (T. 689-690), Staff has more precisely measured those portions of the incentives which should be shared. (T. 1500) The Commission finds that Mr. Hilton has measured the actual percentage of the financial performance measures included in each of the incentive programs, which Mr. Marcus did not do. Therefore, the Commission adopts Staff's proposed adjustments to these four incentive programs as more precise.

The Commission, however, finds that, as discussed by Mr. Marcus, the Long-Term Incentive Plan, the Equity Awards, and the Restricted Share Awards, totaling $1,879,525 (T. 689) as well as EAI's Stock Option Incentive Program, totaling $15, 365,000 (T. 690), "are based entirely on stock price of the parent company." (T. 692)

Having found no direct or measurable benefit to ratepayers of these types of incentives, the Commission directs that these costs not be included in rates.

As to Mr. Marcus' recommendation to disallow certain perquisites provided EAI's Chief Executive Officer and the five top executives at Entergy Corp. which include club dues, financial counseling, the corporate airplane, and a tax "gross-up", the Commission finds no substantial evidence to support the recovery of such expenditures from EAI's ratepayers. The Commission finds that, as noted by Mr. Marcus, these types of expenditures are unreasonable in light of the salaries paid Entergy's top executives. The Commission therefore disallows these perquisites.

Director and Officer Liability Insurance

EAI's application included $191,580[38] in expenses for Director and Officer Liability ("D&O") Insurance. Staff witness Plunkett recommends a 50% sharing of these costs, pursuant to past Commission practice and based on the benefits that D&O insurance provides for both stockholders and ratepayers. (T. 1472) Ms. Plunkett further testifies that her recommendation does not presuppose that this expenditure is unreasonable nor does it imply it is not useful in shielding officers and directors from shareholder litigation. Rather, she continues, her recommendation recognizes that the protection afforded officers and directors is primarily a benefit to shareholders, with EAI providing little evidence of benefits to ratepayers. (T. 1505)

AG witness Marcus, noting similar Commission findings in other dockets, also recommends that these costs be shared equally between shareholders and ratepayers,

[38]Ms. Plunkett removed $95,790 in D&O Insurance from EAI per book, representing 50% of actual expenses. Actual per book expenses would be twice that amount or $191,580.

testifying that the shareholders are the beneficiaries of such policies when mismanagement is the subject of litigation by shareholders. (T. 702, 767)

Mr. McDonald recommends that the Commission reject the Staff's and the AG's proposed adjustment, arguing that the cost is "a reasonable and legitimate cost...to encourage qualified individuals to serve as a member of the board of directors." Mr. McDonald also testifies that the positions taken by Staff and the AG, on this and other similar recommendations would, if carried to every EAI cost, result in leaving EAI without "its legal right to recover the reasonable costs it incurs to provide electric service to its customers." (T. 155)

The Commission agrees that ratepayers, as well as shareholders, benefit from good utility management, which D&O Insurance helps secure. However, as found in prior dockets, the direct monetary benefits of D&O Insurance flow to shareholders as recipients of any payment made under these policies. That monetary protection is not enjoyed by ratepayers. The Commission therefore finds that, because shareholders materially benefit from this insurance, the costs of D&O Insurance should be equally shared between shareholder and ratepayer.[39]

Civic Dues, Donations, and Club Memberships

Both Staff witness Plunkett and AG witness Marcus recommend disallowance of all costs related to civic club dues, club memberships, donations, and other costs such as "institutional advertising, lobbying, and donations, including support and sponsorship of local community organizations and local events." (T. 695.697, 1471) Ms. Plunkett notes that both FERC, which requires these items be listed as non-utility expenses, and

this Commission have, for many years, excluded such costs from consideration in rates as unnecessary to the provision of utility service. (T. 1480-1481) Mr. Marcus testifies that various costs he recommends for disallowance constitute activities which are in fact image advertising, charitable donations for which ratepayers should not be responsible and non-utility expenses such as football outings, golf tournaments, and country club dues. (T. 762-763)

Ms. Plunkett and Mr. Marcus each testify that they used sampling techniques in order to quantify the recommended disallowances. (T. 695-697, 764-765, 1471-1472, 1481-1482) Ms. Plunkett testifies that she limited her application to vendors supplied by EAI for review and proposes a total disallowance of $218,798. (T. 1482) Mr. Marcus tested several accounts, which resulted in proposed disallowances in accounts 500, 580, 921, 907-912, and 930.2 based on review of a sample of invoices provided by EAI in response to data requests. Mr. Marcus recommends disallowance of $652,639 in Accounts 907-912, $176,615 in Accounts 500, 580, and 930.2, and $470 in Account 921. (T. 765)

EAI witness Wright testifies that, although the Company did not intend to include country club dues in its rate request, the other costs related to community activities are reasonable, necessary expenses. Mr. Wright asserts that activities at restaurants, country clubs, football games, civic club meetings, and other local gathering places provide EAI the opportunity to build and maintain relationships, increase dialogue, disseminate information, and "recruit assistance...to support Economic Development efforts....". (T. 553-554) Mr. Wright further testifies that, in addition to certain errors

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[39]Moreover, as discussed earlier, Entergy Corp. has competitive businesses. They also benefit from D&O insurance, and requiring ratepayers to pay the full cost of that insurance would constitute an improper

made by Mr. Marcus in his calculations, the samples used by Staff and the AG were not appropriately drawn. Mr. Wright asserts that the samples had been limited to certain amounts and vendor names and the results should not have been applied against the entire population in the accounts. (T. 555-557) Based on his review and corrections, Mr. Wright concludes that Staff's adjustment should be limited to a disallowance of $68,000 and that of Mr. Marcus to $65,000. (T. 557)

The Commission finds Mr. Wright's justification for ratepayer funding of these various expenses unpersuasive. The expenses include thousands of dollars for:

- football tickets and outings,
- concerts, from the symphony to Kid Rock ,
- cookies, buck knives, and bath products,
- golf balls and golf tournaments, both in and out of state,
- functions and dinners for political figures, both in and out of state,
- hot air balloon championships, and
- liquor.

Such expenditures provide no discernible ratepayer benefit and should be excluded from rates.

Although EAI admits that certain expenses, such as donations and country club dues, should only be included in non-utility accounts, (T. 1769) many of these non-utility expenses were nevertheless included in utility accounts and in EAI's requested rate increase. Because of EAI's failure to account for these costs correctly or to make appropriate corrections or disclosures when filing for a rate increase, the Commission is

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subsidy from the regulated portion of Entergy Corp.'s operations to the unregulated.

disinclined to rely on the validity of the records which EAI has provided. The Commission is also disturbed by EAI witness Wright's testimony regarding the sampling employed by Staff and the AG, in which he criticizes Staff's and the AG's use of limited data as applied to the accounts in question and recommends that disallowances be limited only to those invoices each identified as non-utility. (T. 556-557) The Commission finds such testimony especially inappropriate because it was EAI which limited the data available to both, claiming that providing all the requested and needed data would be "burdensome." (T. 765-766, 1482)

The Commission finds that EAI has provided no credible evidence to support their claim that any of these expenses in the accounts are related to the provision of utility service. The Commission further finds that the analysis performed by Staff and especially the analysis performed by the AG provide the best measure upon which the Commission can determine which costs are not utility-related. The Commission notes that EAI had three opportunities in which to put into evidence the exact costs which make up these accounts: (1) when it filed its Application; (2) when it filed its Rebuttal testimony; and (3) when it filed its Sur-surrebuttal testimony. EAI chose not to do so. The Commission, having found Mr. Marcus' examination of these accounts to be thorough despite the limitations imposed upon him by EAI, adopts the AG's total dollar disallowances for purposes of calculation of EAI's revenue requirement.

Affiliate Rules Compliance Costs

AG witness Marcus recommends that the Commission disallow 50% of the costs incurred by EAI to comply with the Commission's Affiliate Transaction Rules. (T. 761) Mr. Marcus testifies that he agrees that such costs are legitimate and needed for the

enforcement of affiliate rules created to protect ratepayers from subsidizing non-utility affiliate activity. However, Mr. Marcus also testifies that ratepayers should not be financially harmed by EAI's compliance because such rules, and the costs to comply with them, would not exist if there were no affiliates. (T. 765) Mr. Marcus acknowledges that some of these compliance costs relate to other types of rules, such as FERC's transmission's codes of conduct, which do not directly protect ratepayers from providing subsidy to affiliates. (T. 761) To recognize costs related to these other types of rules, Mr. Marcus recommends that only 50% of compliance costs be disallowed. (T. 761)

Mr. Wright testifies that, irrespective of Mr. Marcus' conclusions, none of these costs would be incurred if it were not for the existence of the Commission-mandated Affiliate Transaction Rules. Mr. Wright testifies that these Rules are enforced entirely upon the regulated utility, that any violation of those rules would result in penalties assessed against the utility alone, and that to disallow these compliance costs would be "unreasonable and could be considered an unlawful confiscation of utility property." (T. 561-N)

The Commission finds that the costs of compliance with the Affiliate Transaction Rules will provide a substantial benefit to ratepayers, especially given the substantial, material cost affiliate abuse by utilities could have on those same ratepayers. The Commission, therefore, rejects the AG's proposed sharing and will allow 100% of these costs to be included in revenue requirement. The Commission, however, reserves the right to revisit this issue, as utilities seek out new corporate configurations and additional affiliate activity in the future.

Industry Organization Dues

EAI witness McDonald recommends the Commission approve 100% of industry dues in the amount of $1,237,426[40] for the Electric Power Research Institute ("EPRI") and Southeastern Electric Exchange ("SEE"), testifying that these organizations benefit EAI and its ratepayers through research and development and sharing of best practices. (T. 113-114) EAI witness Wright recommends that the Commission allow all but $150,502 of the $570,084[41] dues for Nuclear Energy Institute ("NEI"). (T. 561-U) AG witness Marcus indicates EAI has accepted his disallowance of 49% of Edison Electric Institute ("EEI") membership fees (T. 765).[42] Staff witness Plunkett recommends 100% disallowance of these costs, noting the Commission's prior finding that these costs do not provide direct ratepayer benefits. Ms. Plunkett therefore recommends a disallowance of $269,543 for EEI, $15,017 for SEE, $1,222,409 for EPRI, and $70,085 for NEI. (T. 1485) AG witness Marcus has analyzed the expenditures of both NEI and EEI to quantify any activity which provides no direct ratepayer benefit. He concludes that portions of the membership expenses should be disallowed based on his analysis indicating that approximately 49% of EEI activities are promotional or lobbying. Additionally, he testifies that, although his access to NEI records was limited, at least 50% of activities appear to be non-utility related and, thus, recommends a 50% disallowance of NEI membership costs. (T. 699-702, 765-766, 2030)

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[40] $1,222,409 EPRI dues plus $15,017 SEE dues. (T. 1485)

[41] AG witness Marcus recommended disallowance of $285,042 representing 50% of all NEI dues, with 100% of NEI dues twice that amount, or $570,084. (T. 561-U)

[42] EAI's currently proposed revenue requirement contains neither disallowance. (T. 168)

The Commission is aware that new technology and possible technological breakthroughs regarding the generation, transmission, and distribution of electric power are being explored by the utility industry. The Commission is concerned that, absent a more affirmative policy position from the Commission, there may be a diminished incentive for utilities to pursue investment in those new technologies - technologies which could provide more efficient utility operation with direct ratepayer benefit.

The Commission seriously considers the testimony as to the numerous benefits EAI and its ratepayers have received because of EAI's membership in various industry organizations. (T. 147-152, 1632-1340, 1720-1722) The Commission also finds that such testimony affirmatively ties certain benefits received to utility operations, although the witnesses have not specifically quantified these individual benefits. EAI's description of the technological advancements which are available through these organizations is persuasive.

Therefore, the Commission finds that membership in EPRI and SEE appear to provide overall benefits, as the organizations' costs are incurred primarily for technological advancement or best practices activities. With regard to NEI and EEI, the Commission is also persuaded that benefits for ratepayers do exist, but that these organizations also heavily participate in certain lobbying and promotional activities which do not provide ratepayer benefits. EAI provides little quantification of those activities which are utility-related and directly benefit ratepayers in contrast to those that do not. Therefore, the Commission, having considered EAI's failure in this regard and in view of the analysis performed by AG witness Marcus (T. 2027-2035), finds Mr.

Marcus' proposed disallowances for both NEI and EEI dues reasonable and supported by the record and adopt them here.

The Commission recognizes that this decision, regarding these costs, represents a departure from prior rulings. While the Commission will allow recovery of these costs at this time, in all future cases, the Commission will require significantly more support than EAI assertions. Therefore, the Commission directs EAI to file, with any future general rate filing or in any request it may make for recovery of these costs, a cost analysis reflecting all benefits it deems it has received over the prior 24 months from any trade organization for which it seeks membership cost recovery. That cost analysis shall quantify each utility-asserted benefit of membership, showing the tie between the organizations' activities and the benefits which are provided directly to ratepayers. EAI shall also file testimony in support of any analysis it provides.

Nuclear Outage Expense

AG witness Marcus testifies that the test year amortization of ANO One Nuclear Refueling costs are greater than the amount expected, based on the latest costs for that refueling. Mr. Marcus recommends that this amortization be adjusted to reflect that more current level. (T. 693-694) EAI witness Wright testifies that the current refueling has been completed and the actual cost amortization based on that current refueling is $21,235,135, which Mr. Marcus accepts. (T. 557, 760) Therefore, the Commission finds this level of ANO One Nuclear Refueling cost amortization appropriate and adopts that amount.

Other Operating Revenues

AG witness Marcus testifies that EAI failed to update its Trip Charge revenues, Reconnect Charge revenues, and Returned Check Charge revenues, all of which experienced fee increases during 2005 and none of which EAI updated in its pro forma year. Mr. Marcus recommends these revenues be updated to reflect expected changes. Mr. Marcus also recommends that interest on Deferred Payment Arrangements be reclassified as utility revenue rather than be considered "below-the-line" or non-utility. Mr. Marcus notes that, under the MBSA, all of the accounts receivable are included in rate base to earn a return. Mr. Marcus states that any Deferred Payment interest reflected in those accounts receivable will also earn a return. Therefore, Mr. Marcus testifies that this small level of service revenues, only $26,000 in 2006, is more appropriately shown as utility revenues. (T. 703-704)

EAI witness Meyer responded by updating his test year revenues for the fee increases. (T. 2567) In his Surrebuttal testimony, Mr. Marcus first testifies that although EAI made certain appropriate adjustments to test year for the fee updates, EAI failed to update for the pro forma year. Mr. Marcus testifies that, as indicated in a data request response from EAI, during the aftermath of Hurricane Katrina, which fell within the test year, EAI extended a moratorium on service shut offs, which resulted in abnormally low revenues for the various revenues at issue. (T. 767-768) Therefore, Mr. Marcus recommends that these accounts be adjusted to a normal, annualized pro forma level, which incorporates the fee increases during the test year, adjusts for lower revenues caused by Katrina, and updates those revenues to reflect expected pro forma levels. In addition, Mr. Marcus testifies that EAI did not respond to his

recommendation regarding reclassification of interest revenue on Deferred Payment Arrangements. (T. 703-704, 767-768)

The Commission finds Mr. Marcus' analysis, which incorporates the fee changes with normalized test year data and updates the revenues through the pro forma year, is reasonable and is the best estimate for ratemaking purposes. The Commission also finds reclassification of interest on Deferred Payment Arrangements to above-the-line Account 451 for ratemaking purposes is, as Mr. Marcus testifies, consistent with inclusion of those charges as part of Accounts Receivable, for which EAI earns a return. Therefore, the Commission adopts the AG's pro forma balance for the fee revenues in the amount of $3,977,000 (T. 768) and approves, for rate purposes, reclassification of the interest revenues reflected for the test year on EAI's books to Account 451.

Income Taxes

Conversion from Flow-Through Method to Normalization Method

Staff witness Hilton recommends that EAI be directed to: convert from the Flow-Through Income Tax method it currently employs to the Tax Normalization method, which should reduce income taxes to the ratepayer; calculate its current revenue requirement incorporating that method; and, maintain sufficient records to prospectively verify compliance in this regard. (T. 1502-1503) EAI witness Wright agreed to make this change and filed, with its currently recommended revenue requirement, income tax expense which reflects the Normalization method. Mr. Wright also recommends that the tax method be applied prospectively only. (T. 545-548) Mr. Hilton subsequently incorporated Mr. Wright's calculation into Staff's proposed revenue requirement in his Surrebuttal testimony. (T. 1516-1517) In response, Mr. Wright noted

that Staff's tax calculation had incorrectly incorporated certain aspects of EAI's current revenue requirement position rather than its own, and should be adjusted accordingly. (T. 561-V) Mr. Wright testifies further that the appropriate level of income taxes, using the Normalization Method, will be dependent upon the final Commission determinations made in this docket. (T. 561-V)

The Commission, finding no opposition to implementation of Income Tax Normalization and that the change should provide ratepayer benefit, approves that method to be applied prospectively and directs EAI to utilize the method when submitting its compliance revenue requirement and cost of service.

Manufacturing Deduction in Tax Calculation and
Revenue Conversion Factor

Mr. Marcus recommends that the Commission direct EAI to incorporate the manufacturing tax deduction allowed under the American Jobs Creation Act of 2004 ("Jobs Act"). That statute, according to Mr. Marcus, is applicable to EAI's generation function and will allow a deduction of six percent of taxable income for 2006 and, beginning in 2007, a 7% deduction. Mr. Marcus calculates the credit allocating taxable income to generation based on the generation function's overall percent of rate base, using a 6% rate assuming a mid-pro forma year. (T. 712-713) EAI witness Wright testifies that EAI is in agreement with that prospective deduction, (T. 561) and Staff witness Hilton testifies that Staff also supports the deduction's incorporation into revenue requirement using Mr. Marcus' methodology. (T. 1503)

The Commission finds the proposed application of the deduction reasonable and reasonably known and directs EAI to incorporate that deduction into its compliance

revenue requirement and cost of service, using the rates and methodology proposed by AG witness Marcus.

Mr. Marcus also recommends that the deduction, which is directly tied to the generation portion of taxable net income, be incorporated into the revenue conversion factor, appropriately reflecting the tax impact of the deduction on incremental revenues. (T. 716-717, 769) Mr. Hilton testifies in support of the deduction and states that Staff appropriately incorporated the deduction into its currently recommended conversion factor. (T. 1503) EAI witness Gillam testifies that the deduction "is not a direct result of a statutory income tax rate..." and, therefore, should not be included in the factor. (T. 2280) Mr. Gillam asserts further that "it is extremely difficult to rigorously quantify a specific tax rate adjustment going forward...due to the expected year by year variability of the tax deduction..." and recommends that the deduction not be included in the revenue conversion factor because it "is not warranted." (T. 2305-2306)

The Commission finds that the deduction is directly tied to incremental taxable income and has the same general effect as that of the state tax rate. The Commission disagrees with Mr. Gillam's assertion that the annual variability of the rate for the deduction limits its applicability here. The Commission sets current revenue requirement, based on the known measurements of revenues and expenses, tax rates, <u>and</u> tax deductions, at one point in time. All of those elements of revenue requirement are subject to significant variability prospectively. As with any of these other revenue requirement elements, then, the prospective variability of the manufacturing rate is irrelevant. The Commission adopts Staff's proposed application of the manufacturing tax deduction as part of EAI's revenue conversion factor in this docket.

RATE SCHEDULE REVENUES

Billing Determinants/Base Rate Revenues Growth Adjustment/Weather Adjustment

EAI witness Meyer testifies that EAI's proposed pro forma billing determinants were established by first determining the individual customer actual monthly usage in 2005 to set as test year, to which EAI then applied a reasonable year end adjustment[43] and a reasonable temperature adjustment to reflect normal weather. (T. 2562) Staff witness Swaim notes that EAI has "proposed pro forma temperature normalized billing determinants[44]...as well as Peak kW demands."[45] In this regard, Mr. Swaim testifies that he verified, through testing, that EAI's proposed test year billing determinants were consistent with those underlying the financial records and revenues in the test year and concluded they were "materially accurate". (T. 2673) Mr. Swaim, however, testifies that significant differences in methods used for the customer growth adjustment and for the weather adjustment exist between Staff and EAI and result in significant differences in total billing determinants and revenues, with EAI proposing approximately $20 million[46] less in revenues. (T. 2679)

Mr. Swaim found EAI's weather adjustment overly complex, relying on hourly temperature data, multiple Heating Degree Day ("HDD") and Cooling Degree Day ("CDD") measures to be applied within each day, and which are "highly correlated to

[43]EAI witness Meyer annualized the last month's usage in the test year to calculate his "growth" adjustment or "year end adjustment". (T. 2560)

[44]Billing determinants include customer counts, kilowatt-hours [kWh], billed kilowatt volumes (kW), and lighting fixture counts. (T. 2670)

[45]KW demand methods addressed include coincident peaks ("CP"), non-coincident peaks ("NCP"), and maximum diversified demands ("MDD").(T. 2670)

[46]Rate Schedule Revenue from Staff Exhibit ARWB-3, ln. 11, of $923,790,000 (T. Ex. 1147) less EAI Rate Schedule Revenue from Exhibit PBG-7, p. 1 of 2, ln 4 of $903,576,000 (T. Ex 903), equals $20,214,000 difference between Staff and EAI.

each other," with the high correlation coupled with adjustments to each class most likely to result in unreasonable results. (T. 2675-2677) To test the reasonableness of EAI's results, Mr. Swaim explains that he applied EAI's method to internal test year revenue projections,[47] known as AGM, to weather adjust pro forma revenue and found that, after adjustment for growth, EAI's pro forma revenues were $20 million less that its own budgeted levels. (T. 2679) He further testifies that the use of AGM for purposes of a reasonableness check is an appropriate method for validation of the results. (T. 2692)

Staff witness Swaim recommends adoption of his calculated billing determinants and resulting revenues, testifying that he has applied the same Commission-approved model from recent cases, which uses five years of monthly data, to set customer base usage, upon which the weather adjustments for HDD and CDD are applied (T. 2679-2681, 2689, footnote 3) and which is also used to measure the expected growth rates. (T. 2689-2690) He further testifies that he tested the results from his billing determinant analysis against those using the AGM and found the comparison reasonable. (T. 2680-2681)

AG witness Marcus testifies that he has estimated expected residential retail determinants, the results of which, although reached using slightly different methods, are comparable to those proposed by Staff. (T. 756)

EAI witness Meyer objects to Staff's use of the AGM which is partially based on older weather models (T. 2562) and objects to Mr. Swaim's calculation of customer base usage to which the growth adjustment is applied, arguing it contains some measure of

[47]The EAI-supplied revenue calculation, Adjusted Gross Margin ("AGM"), is a measurement used by EAI for internal budgeting and reporting. (T. 2679)

weather variance[48] which overstates the adjustment (T. 2564-2565), and testifies that Mr. Swaim's model for growth may have captured the impact of Hurricane Katrina victims influx into EAI service territory. (T. 2565) Mr. Meyer also objects to both Staff's and the AG's reliance on the historical per book billing data for purposes of adjusting for growth, asserting that the adjustment inappropriately extends past the pro forma year and, therefore should not be adopted for setting rates. (T. 2559) EAI witness Wright, however, recommends that, should these billing determinants be approved and because of the extension past the pro forma year, both "additional capacity costs related to the additional sales and increased O&M costs at the June 2007 level should be included." (T. 560)

Responding to criticism of EAI's weather adjustment model, EAI witness Lynch testifies that the model does not display multicollinearity as asserted by Mr. Swaim. Mr. Lynch asserts that, rather, because it applies temperature bands in recognition that usage is not linear with regard to temperature, EAI's model will actually produce a more accurate result. (T. 2513-2515) Mr. Lynch also expresses concern that Staff's model, based on billing months which may lag usage months, inappropriately applies the monthly weather degree day adjustment to the wrong determinants. (T. 2519-2520) Finally, Mr. Lynch addresses certain concerns he has with AG witness Marcus' weather adjustment, but concludes that the Marcus results are not significantly different from those of EAI. (T. 2523)

The Commission finds the test year billing determinants as proposed by EAI and recommended by Staff reasonable and adopts them for this case. (T. 2673) The

[48]EAI witness Lynch testifies that Mr. Swaim's use of the lowest usage months to establish his "base" usage does not account for the weather impacts in that month. (T. 2520)

Commission also finds Mr. Swaim's and Mr. Marcus' use of historical billing determinant data in determining appropriate pro forma adjustments an accepted method which is reasonable and produces reasonable results.

The Commission finds that the use of the growth factor calculated based on five years' of historical data and applied to known and measurable billing determinants is an appropriate and accepted method (T. 2688) for purposes of setting rates and differs little from Mr. Meyer's own use of a year-end annualization. Both methods are employed to estimate the expected level of billing determinants which will occur in the future. In this regard, the Commission finds the five year measure of growth impacts, using Mr. Swaim's model, more reasonably measures and more accurately reflects expected growth than does EAI's method, which takes the customer count from one isolated month and simply multiplies it by twelve. In this regard, the Commission also finds that its adoption of Mr. Swaim's growth adjustment results in no need to further amend either capacity cost or O&M expenses as proposed by Mr. Wright. EAI has filed a fully developed revenue requirement which extends to the end of the pro forma year. Use of known data through the end of the pro forma year will effectively capture any cost changes which are expected to be incurred and for which Mr. Wright expresses concern. The Commission finds, rather, that, when utilizing a pro forma year to capture expected cost increases, had billing determinants not been appropriately updated, a mismatch would have occurred.

The Commission also finds that the weather adjustment applied by Mr. Swaim is reasonable and reflects prior Commission-accepted practice[49] and is adopted here.

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[49]Dockets for which Staff witness Swaim's methodologies have been approved by the Commission include Docket Nos. 01-243-U, 02-024-U, 02-227-U, 04-121-U, 04-176-U, and 05-006-U. (T. 2695, footnote 8)

Therefore, the Commission finds that Staff's billing determinants have been calculated using standard practices accepted by this Commission in prior dockets. The Commission finds that Staff's methods will more accurately reflect the expected levels of billing determinants than those proposed by EAI and will thus more accurately and more appropriately reflect expected revenues than EAI's. The Commission finds that the AG's proposed level of billing determinants and resulting revenues support Staff's results, but, in view of the methodology differences, between Staff and the AG, the AG's billing determinants should not be adopted. Therefore, the Commission adopts Staff's proposed billing determinants and rate schedule revenues in their entirety.

Cost of Service

Demand Allocation Method - Production and Transmission

Production Demand Allocations

A significant component of the overall revenue requirement is the fixed costs of production. These are generally associated with the capital costs, return and depreciation of EAI'S generating plants. Because these costs are not directly assignable to customer classes, they must be allocated to the individual classes. The appropriate allocation method is not susceptible to precise "slide-rule type determination," but is a matter of informed judgment.

There are three different proposals as to the issue of the allocation of demand-related costs that are functionalized to production among EAI's retail classes. EAI witnesses Gilliam and Meyer, Staff witness Bradley, and AG witness Marcus all support the Average and Peak ("AP") method. AEEC witness Falkenberg and Federal Agency

witness Blank support the 1 Coincident Peak ("1 CP") method. Kroger witness Higgins recommends the Average and Excess ("AE") Method.

The AP method considers both average energy usage and peak usage in the determination of each rate class's allocation of production demand costs. The formula for allocation to each class is:

[(Company Load Factor) X (Class % Contribution to Average Demand)]

+ [(1- Company Load Factor) X (Class % Contribution to Peak)]

where:

Average Demand = Energy Usage/8760 hours and

Company Load Factor = Company Average Demand/Company Peak Demand.

The 1 CP method allocates production demand costs to each class based on its contribution to the Company's peak usage in the 1 hour of the year.

The AE method utilizes each class's Non-Coincident Peaks ("NCP") and energy usage in developing allocations:

[(Company Load Factor) X (Class % Contribution to Average Demand)]

+ [(1- Company Load Factor) X (Class % Contribution to Excess Demand)]

where Excess Demand for each class is the proportion of the difference between the sum of all class's NCP and the Company's Average Demand.

It is important to recognize that the determination of allocations in ratemaking is an art, not a science. A primary goal should be to allocate costs on cost-allocation principles; that is, costs should be assigned to those customers or customer classes that caused the costs to be incurred. A corollary to that principle is that costs should be assigned to the customer or class of customers who enjoy the benefits created by the

incurrence of those costs. However, in allocating long-lived assets such as production plant it is nearly impossible to rely solely on cost-causation principles. For example, in the time since the construction of a coal or nuclear plant, many customers for which the plant was built are no longer in the service territory. Further, a utility has a continual influx of new customers for which the plant was not necessarily built.

Perhaps it could be argued that the plant was built based upon projections of customer growth, customer usage growth, and class growth over time. For example, a nuclear unit may have been built in 1980 premised on projections of customers and customer usage through the year 2005. However, that approach is not viable since forecasts are unreliable, and become more so as they move further into the future. Additionally, in many prior cases there were no forecasts of usage twenty-five years into the future.

Regulators generally rely on the usage patterns of current customer classes to develop appropriate allocation factors for the costs of long-lived assets, such as production plant. This is appropriate for two reasons: (1) current customer class usage patterns may reasonably approximate usage patterns in the past; and (2) current usage patterns may be a reasonable basis for determining the current *benefits* that each class receives for production plant. Consequently this Commission considers a blend of the cost-causation principle and the benefits-received principle as a reasonable foundation to develop class allocation factors.

Given those two underlying principles, the Commission will use the AP method for allocating production demand costs among EAI's customer classes for the following three reasons:

(1) The AP method reflects the fact that production plant is built to serve load and provide reliability for 8,760 hours in the year ("Capacity Utilization");

(2) The AP method reflects the fact that much of EAI's production plant was built to provide fuel savings; and

(3) The AP method reflects the fact that much of EAI's production plant was built to provide fuel diversity.

It is also important to note that the Staff has recommended use of the AP Method in EAI's last two rate cases (Docket Nos. 84-249-U and 96-360-U).

The capacity utilization aspect of the AP method is illustrated by EAI witness Meyer. This shows how intensively the capacity is used in each hour of the year. (T. 2575-2578). Further, the fuel savings and fuel diversity aspects of the AP method are discussed by Staff witness Bradley and AG witness Marcus. (T. 720, 770, and 3275) Ms. Bradley states: "The Average and Peak methodology appropriately recognizes that system operations, fuel costs, and fuel diversity are major determinants of generation capacity planning and as such, energy consumption as well as demand are considered in the development of the customer class allocation factors." (T. 3275)

Kroger witness Higgins argues that the AP method results in "double-counting". (T. 989-991) Mr. Meyer provides an example to rebut the double-counting argument made by Mr. Higgins. (T. 2575-2578) However, the Commission disagrees. Mr. Higgins commits a fundamental error in his analysis on this point. He posits that all of the incremental capacity above the system average load that is required for peak conditions is solely attributable to one class ("Peaky Class"). Consequently, he implies that that

incremental capacity should be directly assigned to the Peaky Class. That is not correct. During peak hours it is impossible to say that a particular class is causing incremental load. All classes are causing that peak load in proportion to their demands during the peak period.

Mr. Higgins' example also fails to properly note that the AP method is a capacity utilization method and by definition does not double-count. (T. 989-991) Instead, the AP method is a two-step process. First, each time period is considered separately and is given weight proportional to that time period's proportion of total load (capacity utilization). Second, each class's contribution to load in each time period is weighted by that time period's weight and then summed. In the context of Mr. Higgins example (T. 989-991), July has a weight of 11.67% (1,400/12,000), the Peaky Class share of that 11.67% is given as 900/1,400, and the Flat Class's Share is given as 500/1,400. Similar calculations are done for the other months, the July capacity utilization factor of 11.67% is not used again for the other months' calculations, and hence there is no double-counting.

AEEC witness Falkenberg alleges that the AP method is flawed because, as one class's load changes in the off-peak period, the AP method will automatically change the other class's allocation. (T. 1960-1964, T. Ex. 846-850) Mr. Falkenberg accomplishes this through an artificial construction of an example with two 100% load factor customers.

However, the problem Mr. Falkenberg presents is present in all allocation methods, and cannot be maneuvered around or through. In particular, if one customer class's peak usage changes, the other customer's allocation would automatically change.

In the context of his example, assume two customers, with 100% load factors, 100 MW of load each, and $20 million in production fixed costs. Under either 1 CP or AP, each customer would be allocated $10 million in production costs. He assumes a change in Customer A's off-peak load, with corresponding changes in Customer B's allocation of $20 million, to attempt to impugn the AP method.

Instead, let us assume a decrease of 20 MW in Customer A's usage at the peak. Under the 1 CP method, Customer B, who has not changed usage during either the peak or off-peak, is now allocated $11.11 million automatically because of usage of the 1 CP.[50]

Neither the above example nor Mr. Falkenberg's example illustrates a fundamental flaw with either of the two methods. As discussed above, as usage changes in all customer classes, any allocation method that uses current data will result in class allocation percentages that are different than what would be obtained at the time the generating plant is built. All allocation methods proposed in this case use current data, and avoid the laborious and unnecessary process of vintaging plant allocations, *i.e.*, matching up different allocations with the years that the different units were built.

For simplicity, and in recognition that allocation is not an exact science but is based on informed judgment, utility regulators use allocations from current data as a reasonable approximation of any such complicated "vintaging" of different generating units. Further, current data more appropriately matches up costs and benefits.

Additionally, the AP method appropriately reflects the fact that EAI's baseload coal and nuclear plant, which comprise the vast majority of production demand costs, were built to provide both fuel savings and fuel diversity. The average demand

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[50]Calculated as [100 MW/180 MW] X $20 million = $11.11 million.

component used in the AP method properly weights the fuel savings and fuel diversity benefits in making the AP-based cost allocations.

It is important to point out that fuel savings and fuel diversity are two separate concepts. Fuel savings refers to expected decreases in fuel costs paid by ratepayers because of the substitution of relatively low cost coal and nuclear fuel for higher priced natural gas and oil. Fuel diversity refers to the expected decrease in the variability of overall fuel costs because of the availability of a wide variety of plants using different fuels. This provides a benefit to customers, who prefer less volatility even if there is no expected decrease in overall costs associated with the expanded portfolio of plants. This benefit is analogous to the benefits of diversification of common stock in a portfolio of common stocks, which is well-established in financial theory.

During the late 1970's and early 1980's EAI completed its plan of adding a number of coal and nuclear plants to its generation portfolio for the benefit of EAI's customers. While those plants were built with a goal of meeting future peak demand, fuel savings and fuel diversity were important goals as well.

AEEC witness Falkenberg argues that the justification for EAI's relatively expensive baseload plant was not even partially based upon a desire to provide fuel savings. (T. 1966-1976) This is not correct. It is clear that, especially for EAI's nuclear plants, potential fuel savings was an important factor in the decisions leading to the construction of those plants. The fuel savings from EAI's Arkansas Nuclear One units vastly exceed its fixed costs, which inured to the benefit of high load factor industrial customers. Even in the case of the uneconomical Grand Gulf nuclear plant, significant fuel savings have inured to the benefit of EAI's high load factor customers. From cost-

causation and benefits-received perspectives, because of the significant fuel savings associated with EAI's nuclear and coal units, the AP method's inclusion of average demand in the calculations is appropriate.

Additionally, EAI's baseload plants were built to provide fuel diversity. As discussed earlier, fuel diversity is a different concept than fuel savings. Fuel diversity also disproportionately benefits high-load factor customers. At the time EAI's nuclear and coal units were planned and constructed, the Entergy system and EAI were primarily dependent upon natural gas and oil-fired plants. A rationale for the building of the nuclear and coal units was to provide fuel diversity. From both the cost-causation and the benefits-received perspectives, the AP method's inclusion of average demand in the calculations is appropriate because of the significant fuel diversity associated with EAI's nuclear and coal units.

Consequently, the Commission finds that the AP method should be used to allocate production demand costs among EAI's retail rate classes in this case. We reject the 1 CP method since it only considers 1 hour out of 8,760 hours during the test year and does not consider the benefits of fuel savings and fuel diversity associated with EAI's nuclear and coal units. The Commission also rejects the AE method because consideration of non-coincident peaks has little bearing in cost-causation for production plant. The Federal Agencies' proposal to use minimum base usage instead of average energy usage is flawed because it does not adequately reflect all of the fuel savings and fuel diversity benefits of EAI's baseload plant. Mr. Falkenberg also proposes an alternative AP method based upon one in the 1992 National Association of Regulatory Commissioners ("NARUC") Cost Allocation Manual at page 57. (T. 1832-1833) However,

that particular method is flawed because, instead of using the system load factor for weighting purposes, it uses a factor that artificially inflates the portion of fixed costs that are considered "demand-related".

Transmission Demand Allocations

EAI, Staff, the AG, and the Commercial Group recommend or accept the use of the 12 Coincident Peak ("12 CP") method to allocate transmission demand costs. (T. 2540, 2580-2581, 2608, 3300-3301, 720, 772) AEEC and the Federal Agencies support the use of the 1 CP method to allocate transmission demand costs. (T. 1831, 1977, 1066-1069)

The parties that support the 12 CP method argue that it: reasonably reflects the mix of customers' respective electrical load characteristics and the relative costs to serve such loads throughout the year; considers the need for stable levels of reliability throughout the year; and reflects that transmission is connected to generation. Additionally, they point out that baseload generation requires more generation than peaking facilities, and that the 12 CP method is used by the FERC to allocate transmission costs. (T. 772, 2539, 3300-3301)

The parties that support the 1 CP method state that the transmission system was sized built to serve the single system peak and that, although the 12 CP method may be appropriate at the wholesale level, it would not be inconsistent to allocate transmission demand costs among EAI's retail classes using the 1 CP method. (T. 1066-1068, 1831)

The Commission agrees with the arguments in support of the 12 CP method as applied to the retail wholesale allocation and the retail rate class allocations and adopts that methodology.

Customer Service and Information Expenses

With regard to Accounts 907, 908, and 910, Customer Service and Information expenses, Mr. Marcus, based on his review of the items contained in this account, recommends that the Commission allocate these on the same basis as EAI has allocated its sales and marketing expenses. (T. 722) Mr. Marcus testifies that these accounts reflect very specific expenses related entirely to large classes or are other costs, which were listed as "economic development", but relate to civic club and charitable activities and communicating with community leaders regarding energy matters. Mr. Marcus, therefore, concludes that assigning 84% of those costs to residential customers is not appropriate. Mr. Marcus states that, while EAI witness Gillam did adjust certain accounts, the majority of information he has reviewed indicates that a customer count allocation is not appropriate, with large customers receiving almost none of these costs, and recommends that the Commission approve an allocation which reduces the "extent to which residential customers subsidize these activities." (T. 775). Mr. Gillam testifies that EAI has followed the appropriate accounting as required by the NARUC Electric Utility Cost Allocation Manual which requires that these costs be deemed "customer-related." Mr. Gilliam, therefore, applied the allocation factor which is based on "customer count", is wholly appropriate, and should be adopted. (T. 306-307)

The Commission finds that Mr. Marcus' proposal to set an allocation factor, which fairly allocates these costs based on the makeup of the "customer related" costs EAI posts to these accounts, is appropriate. The Commission finds that EAI's policy to recognize these costs as "customer related" as required by NARUC guidelines was also appropriate, as was its initial assignment of customer count as a basis to allocate these

costs. However, the Commission also finds that, in view of the analysis provided by Mr. Marcus, the actual expenditures reflect that the "customer-count" allocation would not be appropriate. Many of these costs appear to directly benefit commercial and industrial customers. (T. 773-774) Mr. Marcus' recommendation is to use a "broad based" allocation factor and proposes the Commission adopt the "total utility plant" allocator. The Commission finds this change will result in a more fair allocation of these costs and, thus, adopts it here.

Miscellaneous Service Revenues Allocation

AG witness Marcus testifies that his analysis of the Rate Schedule 29 revenues contained in "Account 451 (other than EAI's adjustments from AJ01 and AJ04) are paid (almost entirely, some 95%) by residential customers... (and are related to)...trip charges and reconnections associated with non-payment and costs of returned checks." (T. 722-723) Mr. Marcus recommends that these revenues be allocated "using the retail customer accounting costs excluding uncollectibles, with no allocation to wholesale... (which would) assign 80% of the revenues to the residential class, generally commensurate with the underlying costs." (T. 723) EAI witness Gillam amended EAI's original filing to reflect certain re-allocations but also states that "(d)ue to the general nature of these revenues, it is appropriate to allocate them based on the total revenue requirement for the Arkansas retail jurisdiction." (T. 2282) Mr. Gillam also testifies that "(t)o do otherwise, would require a level of analytical time and effort that is not warranted give the materiality of the revenue involved." (T. 2307) AG witness Marcus, however, asserts these revenues are not "general", are paid predominantly by residential customers for specific services, and should be allocated as he recommends. (T. 775)

The Commission finds that the evidence indicates the appropriate allocation of the revenues should, as Mr. Marcus points out, follow the costs associated with their generation. The Commission also notes that the "analytical time and effort" appears to have been already expended by Mr. Marcus in this regard, having identified the makeup of the revenues and makes his recommendation based on that effort. Therefore, the Commission adopts the allocation as proposed by the AG.

Storm Damage Reserve Allocation

AG witness Marcus testifies that, according to EAI witness Wright, approximately 62% of the Storm Reserve is production related. However, Mr. Marcus points out that the Storm Reserve and its related costs are allocated using only transmission and distribution factors and therefore had requested that EAI provide clarification. (T. 752-753) The Commission finds that, because it adopts no balance for the Reserve, the allocation issue will relate only to the Storm Damage expense. The Commission finds that the functional makeup of the allowed expense should dictate its allocation to class. Therefore, the Commission directs EAI to allocate the expense based on the factor which most closely reflects the functional cost incurrence of those costs used in the calculation of the Commission adopted normal expected Storm Repair Expense of $14,449,000. The Commission also directs Staff to review the subsequent allocation EAI incorporates into its compliance filing and report its determination to the Commission at that time.

Rate Design

Large General Service Time-of-Use Class ("LGSTOU") and Large Power Service Time-of-Use Class ("LPSTOU")

Combine Classes

Staff witness Bradley testifies that EAI proposes combining the two large time-of-use ("TOU") classes, Large General Service TOU, or LGSTOU, and Large Power Service TOU, or LPSTOU, into one class. Ms. Bradley recommends that, in view of the significant adverse rate impact to LGSTOU customers, the Commission should reject this proposal or, in the alternative, require a rate design which would mitigate the inter-class impact. (T. 3278, 3306) EAI witness Meyer testifies that the impact, for which Ms. Bradley expresses her concern, was related to an isolated customer, whose pattern of consumption resulted in a significant percentage increase. In this regard, Mr. Meyer also points out that, for almost 95% of LGSTOU customers, the impact is less than or equal to only 16%. Mr. Meyer states that EAI proposed merging these schedules because of the confusion regarding rate design for LGSTOU customers as they exceed the maximum demand and become eligible for LPSTOU service. Mr. Meyer continues to recommend combining these classes, but, should the Commission not wish to combine them, he recommends that each class maintain "their respective rate structure by increasing each pricing component by the same percentage increase." (T. 2582-2583)

The Commission finds a 16% shift significant and that, as large and presumably sophisticated customers, any confusion the LGSTOU customers experience does not warrant that shift. The Commission, therefore, adopts Staff's recommendation to keep these two classes separate. The Commission, however, adopts EAI's suggestion to maintain the current rate structure.

Residential Rate Block Structure, Residential Water Heating, Commercial Water Heating

AG witness Marcus recommends certain changes to rate design for residential customers and for commercial customers. Mr. Marcus testifies, first, that EAI proposes no changes be made to the current residential block structure and that any increases be assigned to each declining block in the same proportion currently reflected in rates. Mr. Marcus testifies that, because of the AG's long-term policy to encourage conservation and increased efficiency through use of natural gas, it is his proposal that fixed charges be minimized and block rates be designed on an inverted basis for residential customers. (T. 726-729) Mr. Marcus recommends that, to minimize any sudden rate impact, a gradual change in design to a "flat or inverted summer rate, a lower flat winter rate, and limited reliance on customer charges" should be implemented, the result of which should be that weather sensitive customers, who contribute to the winter peak, will be required to pay the higher cost they incur. (T. 727)

Mr. Marcus also recommends that the Commission close to all new customers the promotional rate RW residential water heater tariff and the Rider M14 commercial customer water heater tariff, testifying that the subsidized service is wasteful and promotes inefficiency. Mr. Marcus recommends that the Commission consider similarly closing the winter rate to new customers and replacing it with a flat rate. (T. 730) Mr. Marcus asserts that EAI relies upon findings made in 1992 as a basis for opposition to his proposed changes and that such findings are no longer valid. Mr. Marcus testifies that there have been changes since 1992 that include considerably higher gas costs, with the resulting increase in EAI's marginal costs, thus, making his rate design more

economic, and the increasing understanding of costs related to greenhouse gases. (T. 776-779)

Staff witness Bradley testifies that she does not oppose the AG's proposals, conceptually; however, she recommends that "(a)ny significant changes to rate design must take into consideration customer impact." (T. 33053)

EAI witness Meyer opposes Mr. Marcus' rate design changes, asserting that Mr. Marcus provides no analysis to support a change to inverted block rates nor does Mr. Marcus provide analysis to support his assertion that the current water heating and winter tail block rates are not cost justified. Additionally, Mr. Meyer testifies that the Commission has already reviewed and approved the current promotional rate structure in Docket No.90-205-R and that these rates were not at issue in EAI's last rate case. (T. 2589-2590) Mr. Meyer recommends the Commission reject these proposals as not cost justified. (T. 2590)

The Commission finds that the current rate filing is not the appropriate docket in which to raise issues related to conservation and efficiency and effecting these standards through significant changes in rate block design. The impact of the design changes Mr. Marcus proposes should be more carefully considered in a separate proceeding, with customer rate and overall bill impact measured, as well as determining what the resulting revenue impact will be. Therefore, the Commission rejects, for now, the AG's rate design changes regarding the current block structure. The Commission anticipates investigating these rate design proposals within the context of the Commission Docket No. 06-004-R, regarding conservation and efficiency.

However, the Commission is persuaded by Mr. Marcus that changes since 1992 in gas cost and the increasing understanding of the environmental costs of greenhouse gases have rendered the promotional water heater tariffs no longer appropriately efficient or cost effective as Mr. Marcus asserts. (T. 777) The Commission, therefore, adopts Mr. Marcus' proposal to eliminate the RW tariff and the commercial Rider M14, with the proviso that current customers, at their current locations, will be grandfathered under the tariff and may continue service until such time that these customers change location.

In keeping with his proposals regarding the redesign of block rates, Mr. Marcus also proposes that, for any rate decrease, the entire decrease be applied to the first block of energy charges for both summer and winter rates and, for any rate increase, that it be applied to the tail-block, with no change made to the current customer charge. (T. 730) EAI witness Meyer opposes freezing the customer charge should a rate increase be warranted, citing the results of its cost of service which indicates, from a cost-based perspective, that an increase in the customer charge rate from the current $7.73 to $13.52 should be made. (T. 2590)

Given its prior determination with regard to the AG's proposed changes in rate block structure, as well as the import of maintaining rates which are cost-based, the Commission rejects the specific adjustments Mr. Marcus proposes and adopts EAI's proposed design.

Rate Increase Assignment to Each Rate Class

Kroger witness Higgins recommends that EAI's proposed revenue increase be allocated to rate class using "the midpoint of the Energy & Peak and Average & Excess

Demand cost of service results, adjusted for incremental credits for additional facilities and standby services charges" and he provides a table which shows the percentage increase by class this method would provide. (T. 1003) EAI witness Meyer opposes Mr. Higgins' proposed variance from cost based rates, which will be reflected in the final Commission approved cost of service. (T. 2587)

Commercial Group witness Gregory recommends that any rate increase be assigned to a lesser degree to those customers which currently reflect a higher rate of return. (T. 605) In responding to Mr. Gregory's recommendation, Mr. Meyer testifies that, as he understands that proposal, it should move rate classes closer to cost of service and, therefore, he agrees it is appropriate. (T. 2588)

The Commission finds that, in keeping with its prior determinations, increases or decreases in rates should, for the most part,[51] reflect the overall cost of service. In this regard, Kroger witness Higgins' application of his allocation method in assigning increases is not appropriate and is rejected. The Commission finds, in this case, that the overall results reflected by both Staff and EAI are reasonable. The Commission therefore adopts the cost of service method as approved herein, subject to further findings should the newly run cost of service results reflect unreasonable variations from the results reflected in the record.

Tariffs and Riders

Energy Cost Recovery Rider ("ECR")

All parties agree that continuation of EAI's Energy Cost Recovery rider ("ECR") for fuel and purchased energy costs is appropriate. However, parties recommend various

[51]The Commission may find that results of an appropriately allocated cost of service do not reflect reasonable increases or decreases among the classes.

modifications to it. Subject to the limitation and conditions set forth hereinafter, the Commission agrees that the ECR should continue but that certain modifications are necessary.

EAI witness McDonald testifies that the ECR should include the EAI retail portion of the FERC-ordered bandwidth payments associated with "rough production cost equalization" among the Entergy Operating Companies. (T. 101) Mr. McDonald states that the dollars associated with those payments will flow through Service Schedule MSS-3, Exchange of Electric Energy, pursuant to the FERC's order. However, Mr. McDonald testifies that acceptable alternatives to including these payments in the ECR are a new exact recovery rider, the Production Cost Allocation ("PCA") rider, or inclusion of the payments in base rates. (T. 101)

Staff witness Smith argues that it is inappropriate to use the ECR to recover the costs associated with the FERC decision since the ECR was designed to recover net fuel and purchased energy expenses. (T. 2403/16) Kroger witness Higgins opposes EAI's ECR approach because the charges are the result of a federal mandate and not part of the normal conduct of business, and because the ECR is a straight kilowatt-hour charge while the FERC-imposed bandwidth payments reflect a blend of energy costs and fixed production costs. (T. 985-986) Similarly, AEEC witness Falkenberg agrees with the parties arguing that the bandwidth payments should not be included in the ECR. (T. 1942) However, Mr. Falkenberg also proposes that the ECR be merged with the CM rider proposed by EAI. (T. 1853-1856)

The Commission is not persuaded by the ECR approach advocated by EAI. The Commission agrees with the Staff and other parties that the costs associated with the

FERC-ordered bandwidth payments should, as limited and conditioned hereinafter, not be recovered through the ECR. Instead, these FERC-ordered payments should be recovered in a separate rider such as the PCA. Mr. Falkenberg's recommendations will be discussed elsewhere in this Order.

Staff witness Smith also recommends that the retail ratepayers of EAI should receive through the ECR, as an offset to fuel and purchased energy costs, a portion of any revenues received by the Company as compensation for using SO2 emission allowances in the production of energy. Mr. Smith states that this compensation should be credited to ratepayers through the ECR Rider and the compensation should include SO2 rider revenue received through System Schedule MSS-3 and SO2 adder revenue related to off-system sales.

Mr. Smith also testifies that the retail portion of proceeds received by EAI for the Environmental Protection Agency ("EPA") auction should be credited to ratepayers through the ECR. In addition, Mr. Smith states that, if EAI sells allowances in the market or to other EOCs in the future, those proceeds should be credited to ratepayers through the ECR. To comprehend these proposals in this case, Mr. Smith proposes that the test-year amounts of these proceeds be removed from EAI's cost of service and included in the ECR. (T. 2403/14-2403/15) AEEC witness Falkenberg agrees with Staff's proposal and notes that, because the revenues from SO2 emission sales are volatile and are the subject of a current complaint before the FERC by the Louisiana Public Service Commission, these proceeds should be included in the ECR. (T. 1858-1859, T. Ex. 769-771)

EAI agrees with the Staff's proposed treatment of SO2 revenues but expands it. EAI asserts that, in the future, compliance with a number of environmental regulations will require the purchase of NOx, mercury, activated carbon purchases related to mercury reduction emissions, and limestone purchases related to SO2 compliance. For this reason, EAI witness Gilliam recommends that the ECR should be revised to also include the future costs to the Company of obtaining the necessary allowances. (T. 2298-2299, 2311-2312) EAI witness Castleberry testifies that the costs associated with emission credits and compliance with environmental regulations are volatile and will vary with the amount of coal burned. (T. 1618-1619)

Staff opposes this expansion of the ECR because EAI has not shown that: (1) it has incurred any such costs during the test year; (2) the costs of compliance would exhibit extreme volatility and unpredictability; or (3) recovery of these costs in base rates in a future rate case would not be appropriate. (T. 2403/48)

The Commission concurs with the recommendation of Staff and AEEC on this issue. EAI is directed to include revenues associated with the sale of SO^2 emission allowances in the ECR rider. The inclusion of the other environmental costs in the ECR is not appropriate for the reasons articulated by Staff. However, since these costs have not been incurred during the test year and are not projected to be incurred until the years 2009-13, EAI may seek inclusion of those costs in the ECR at a future date closer to the time when they occur.

Turning to the issue of the appropriate carrying cost to apply to deferred fuel balances in the ECR, Staff witness Smith proposes that the carrying costs be changed from the rate of return approved for EAI by the Commission in a non-appealable final

order to the annual Commission-approved rate of interest on customer deposits. Mr. Smith makes several arguments to support Staff's position. First, Mr. Smith argues that provision of the ECR is discretionary and that the ECR provides a fair balancing of interests, even without carrying charges on any over- or under-recovered balances. Second, the true-up provision in the ECR lowers the risk of EAI under-collecting. Third, the recovery of the deferred fuel balance is not long-term in nature, but instead it is recovered through a surcharge over a projected twelve month period. Finally, Mr. Smith states that the Commission has used the same approach for determining carrying charges for Arkansas' gas distribution utilities. (T. 2403/17-2403/21)

EAI witness Gillam disagrees with Mr. Smith's proposed change in the carrying charge rate and states that the Company essentially finances the under-recovery of fuel and purchased power expense, so that the proper rate of return here is the Company's cost of money. (T. 2297)

Staff is correct regarding the appropriate carrying charge. The Commission adopts Staff's position that the carrying charge rate on the ECR should be changed to the Commission-approved customer deposit interest rate for the reasons provided by Staff. The Commission also agrees with Staff and emphasizes that the ECR is a discretionary tariff and that the new carrying charge is symmetric and fair since it applies to both under- and over-recoveries; that is, if the Company over-recovers, the interest rate that customers receive on that over-recovery is the customer deposit interest rate as well.

AEEC witness Falkenberg argues that the ECR, in addition to the proposed Riders CM and PCA, should be seasonally differentiated and voltage adjusted by customer

class. (T. 1859-1861) The results of both of Mr. Falkenberg's proposals would be to assign more costs to the residential class and less costs to the industrial class.

EAI, Staff, and the AG oppose AEEC's proposed modifications. (T. 2299-2300, 779-781) AG witness Marcus states that the marginal energy costs are similar during the summer and winter seasons for EAI and that a pronounced summer-winter differential would send the wrong price signals to customers. Staff and EAI witnesses state that the current non-seasonally differentiated ECR rider: (1) provides for levelized annual fuel cost; (2) protects customers from unnecessarily high electric bills in the summer months; and (3) would be undesirable for most customers, particularly commercial and industrial customers. Regarding the proposal on voltage adjusted rates, EAI witness Gillam states that "as a result of M1 discounts, customers taking service at primary and transmission have reduced billing determinants." (T. 2300)

For the reasons stated by EAI, Staff, and AG, the Commission rejects AEEC's proposal to modify the ECR rider for seasonal or voltage differences.

AEEC witness Falkenberg also recommends that Staff conduct an annual audit of the ECR rider. (T. 816) Staff witness Smith disagrees with this recommendation and states that Staff already reviews the ECR filings for mathematical accuracy and periodically conducts verification testing. Mr. Smith states that a requirement for an annual audit could result in a less than optimal use of Staff's limited resources. Mr. Smith states that ECR audits are best left to the discretion of Staff and the Commission. (T. 2403/48-2403/49)

Staff is correct. The timing of audits of the ECR is best left to the discretion of the Staff and Commission. A requirement for an annual audit of the ECR will not be adopted.

Staff witness Smith recommends that EAI provide the Commission with an annual report addressing fuel and purchased energy issues with its annual ECR Rider filing. Mr. Smith states that the report should, at a minimum, include eleven detailed items. Mr. Smith asserts that such a report would be useful to the Commission: (1) power markets have become much more complex and volatile than they were in the past; (2) fuel costs represent a significant portion of EAI's costs; and (3) these costs are collected through an automatic adjustment clause. (T. 2403/22-2403/23) In view of EAI's Rebuttal Testimony, Mr. Smith modified his recommendations. (T. 2403-44)

EAI agreed with Staff's reporting proposals and supports one of the modifications proposed by Mr. Smith. However, the Company does not support one item in Staff's modified reporting proposal that would require EAI to "identify when Units are being run out of economic dispatch because of transmission constraints or other factors, identify and explain the factors affecting such dispatch, and quantify and explain the associated impact on EAI's fuel and purchased energy costs." (T. 2403/44) EAI's concern with this reporting item is that it is not developed in coordination with the annual update cycle for Rider ECR. Further, the scenario of an economic dispatch with no transmission constraints represents an unrealistic situation that can never be achieved. As an alternative, EAI suggests that the Company provide the impact on EAI's fuel and purchased power costs associated with atypical events on Entergy's generation and transmission system when units need to run out of merit order.

The Commission agrees with Staff's recommendations regarding the development of an additional report to be included in the Company's annual ECR filing and directs that such report be filed. This report shall include the items as modified by Staff.

Capacity Management Rider ("CM")

In this case EAI proposes two new riders, a Capacity Management ("CM") rider and a Production Cost Allocation ("PCA") rider. The CM rider would permit EAI to recover, or credit, the APSC retail jurisdiction's share of cost changes associated with a variety of capacity-related costs. (T. 2265-2270) The cost changes recovered through this rider would reflect the incremental revenue requirement of capacity costs not recovered in base rates. Under the proposal, these costs would fall into five categories:

(A) Acquired capacity costs associated with EAI's ownership of additional generating capacity;

(B) Purchased capacity costs associated with the capacity cost component of purchased power costs;

(C) Reserve equalization costs associated with changes in the levels of Service Schedule MSS-1 of the Entergy System Agreement;

(D) Deferred capacity costs which are capacity costs deferred by order of this Commission and the balance of which will be recovered and amortized over twelve months; and

(E) Imputed debt cost associated with increased financial risk from fixed components in purchased power contracts.

EAI proposes that the costs included in this rider would be prospective only, with no true-up, and would be re-determined annually. There would be an annual review in which Staff would have approximately three weeks following EAI's submission to review the calculations. After Staff completes its review and corrections of any errors identified

by Staff are made, the annually re-determined rates would go into effect automatically, without an explicit Commission Order. (T. 2265-2270)

The Company makes a number of arguments in support of rider CM. First, EAI notes that, in the future, it will need to acquire additional generating resources to meet its resource planning objectives. The Company does not own or control enough generation to meet the planning criterion that it must control an amount of generating resources that is at least equal to projected peak plus reserves. Further, in order to have a balanced generation portfolio, EAI asserts that it will need to acquire load-following capability in the next few years. Company witnesses have testified that EAI will need to acquire additional generating resources. EAI indicates that it needs to purchase 1,462 MW of capacity in 2007, which will increase to 1,818 MW by 2012. (T. 100, 2331-2333)

EAI testifies that the CM rider would provide EAI with a maximum level of flexibility to act in its customers' interests in contracting for secure power supplies while simultaneously feeling confident that it will receive fair financial recovery for its prudent actions. (T. 97-100, 250)

EAI witness Fetter asserts that credit rating firms, such as S&P, look favorably on such clauses, which could positively impact EAI's credit ratings. (T. 251) Further, according to the Company, as a utility increases its reliance on Purchased Power Agreements ("PPA"), credit agencies, such as S&P, impute a portion of the stream of future fixed PPA payments as debt, which brings about a reduction in the common equity ratio. Mr. Fetter states that this increases perceived risk and the cost of equity will also increase. Rider CM allows for a change in the allowed return on equity between normal rate cases to compensate for the alleged increased risk. (T. 252-255)

EAI witnesses McDonald and Cooper state that the costs covered by Rider CM are material, volatile, and outside the control of the Company and should be considered for automatic adjustment clause purposes. (T. 100-103, 2335-2338, 137-140, T. Ex. 936-937) Mr. McDonald also argues that other State Commissions have approved similar mechanisms to recover purchased capacity costs between rate cases. (T. 141)

Finally, Mr. McDonald notes that, because of the FERC-imposed bandwidth remedy, any increase in CM rider costs between EAI rate cases will decrease EAI's bandwidth payments. Mr. McDonald states that for every $1 increase in the Company's production costs, FERC-imposed bandwidth payments decrease by 80 cents. (T. 145-146, 179)

With the exception of AEEC, all of the other parties oppose implementation of the CM rider. AEEC proposes a significant modification to the Company's CM rider which we will address later.

The Commission is not convinced that the proposed CM rider is appropriate at this time. We agree with the parties' arguments in opposition to the rider. First, the CM rider shifts the risk of fluctuations in capacity costs from EAI and onto customers without providing commensurate benefits to customers. This shift in risk does not adequately balance Company and ratepayer interests. (T. 2403/09) Further, EAI proposes this risk-reduction measure for its shareholders, yet does not propose a corresponding decrease in the allowed return on equity.

Second, the level of costs is not material and currently represents only 1% of EAI's rate schedule revenue requirement. (T. 2403/10) Also, the costs are not volatile. For the period 2000 through 2005, capacity purchase costs have ranged from $1.4 million to

$7.2 million, which does not constitute extreme volatility. In addition, for the most recent three years, 2004 through 2006, capacity purchase costs have not exhibited extreme volatility. (T. 2403/10, 2403/36, 613) Further, the Commission does not agree with EAI that the Company has no control over the costs covered by the CM rider. In contrast with the ECR rider, whose costs are determined by prior portfolio decisions as well as market forces, the Company has significant control over decisions regarding the plant's type, size, location, and dates of construction.

While many utilities have fuel adjustment riders, only a few have capacity adjustment riders similar to rider CM. Furthermore, there does not appear to be an industry-wide movement toward granting capacity adjustment riders in traditional non-retail access jurisdictions. (T. 2403/36-2403/38)

A comprehensive rate review provides a better forum for review and scrutiny of these costs than does the procedure in the CM rider. Moreover, the time constraints embedded in rider CM limit the time for an adequate Staff review and limit participation by other parties in the process. (T. 611-612)

The imputed debt cost component of the CM rider is actually an adjustment to the Company's allowed return on equity. It is neither just nor reasonable for this Commission to give EAI an increase in the allowed ROE though a rider without a full review of existing economic and financial conditions and EAI's overall required rate of return. This is an example of single-issue ratemaking. (T. 614, 982)

In addition, the proposed CM rider creates a mismatch between costs and revenues. The cost of new capacity would be automatically recovered through this mechanism, while existing base rates would allow shareholders to keep all excess

revenues arising from load growth and decreases in existing rate base because of accumulated depreciation. (T. 651, 745, 1853-1854)

To address this last problem and because of the FERC-imposed bandwidth remedy, AEEC witness Falkenberg proposes a broader recovery mechanism in conjunction with the ECR. Mr. Falkenberg proposes that all of EAI's production costs, including those in the ECR rider, the proposed CM rider, and the EAI bandwidth payments proposed for the PCA rider be subject to an exact recovery cost rider with seasonal differentiation. Mr. Falkenberg testifies that this approach is beneficial since it would eliminate the likelihood of over-recovery of the costs of a new plant in the subsequent years after its costs are placed in base rates. Mr. Falkenberg also notes that any incentives for "gaming" accounting entries or inefficient management, which normally occur with pass-through recovery mechanisms, are mitigated by his proposal since most of EAI's production costs are reflected in the bandwidth remedy. (T. 1853-1856)

Staff witness Smith opposes Mr. Falkenberg's proposal. (T. 2403/35) AG witness Marcus also opposes the proposal but considers it a significant improvement over EAI's original proposal. However, Mr. Marcus notes that if this revised proposal is adopted there should be a commensurate downward adjustment in the allowed return on equity because of the decrease in risk. (T. 744-745)

EAI's witnesses indicate that Mr. Falkenberg's proposed modification to the CM rider would be acceptable with the exception of the seasonal rate differential. (T. 143, 2300-2302, 178-180, 2313, T. Ex. 925-931)

The Commission will not approve AEEC's alternative approach to a CM rider (T. Ex. 925-931) for many of the same reasons that we discussed above with regard to EAI's proposed Rider CM. First, this proposal does not appropriately balance the interests of ratepayers and shareholders. If this proposal were approved, a significant proportion of EAI's costs would be automatically flowed through to customers. The only remaining costs not automatically flowed through would be transmission and distribution costs. That significantly increases the risk to ratepayers, without any commensurate benefits.

Second, rather than the expedited and truncated process envisioned in a revised CM rider, the Commission believes that a comprehensive rate review process provides a better forum for review and scrutiny of these costs. The time constraints embedded in rider CM severely limit Staff, intervenor, and Commission review.

Production Cost Adjustment Rider ("PCA") –
FERC-Imposed Production Costs

In 2001, the Louisiana Public Service Commission ("LPSC") filed a complaint at the FERC alleging that production costs among the Entergy Operating Companies are no longer "roughly equal" and thus are not just, reasonable and not unduly discriminatory as required by the Federal Power Act. The LPSC asked the FERC to fully equalize all the Operating Companies' production costs. The Commission intervened on behalf of Arkansas ratepayers and vigorously contested the LPSC's complaint. The FERC, in its Opinion Nos. 480 and 480-A, denied the LPSC's demand for full production cost equalization but determined that rough equalization should be maintained through a bandwidth of +/-11% of the system average production cost. Because EAI's production costs are more than 11% below the system average, it will be required to make significant payments to the other Operating Companies. The Commission has appealed the FERC's

orders to the United States Court of Appeals for the District of Columbia Circuit, and that appeal is awaiting oral argument and the Court's decision.

In the meanwhile, EAI must begin making payments under the bandwidth beginning in July, 2007. In light of United States Supreme Court precedent, particularly *Mississippi Power & Light v. Mississippi*, 487 U.S. 354 (1988), there is little likelihood that a Commission order refusing to pass the costs of those payments to ratepayers would be sustained. The Commission therefore believes that allowing those costs to be passed through to customers at this time is the most prudent course of action. If the Commission's appeal is granted, those costs will be refunded to EAI ratepayers. If it is not, the Commission will pursue its appeal to the United States Supreme Court.

Method of Recovery

EAI proposes three methods for recovering the production costs imposed by the FERC: rider ECR; a new exact recovery rider, *i.e.*, the Production Cost Allocation ("PCA") rider; or base rates. (T. 101) Other parties argue that is inappropriate to recover these costs in base rates or through the ECR rider.

EAI, Staff, and AEEC agree that, because of the volatility of these costs, base rate recovery is inappropriate. (T. 103-105, 2844-2847, 1834-1837, 2972-2973) EAI argues for inclusion of these costs within the ECR rider because FERC has ordered that they be included in Entergy Service Schedule MSS-3. (T. 101) Other parties argue that these costs should be recovered through a separate rider, and should not be recovered through the ECR rider because the costs are not all energy-related. They also argue that the ECR rider is already too complex and customers should be able to directly see the amount of the FERC-imposed charge without the camouflage of the ECR rider. (T. 2403/16, 2972-

2973, 1838-1839) EAI witnesses Gilliam and McDonald agreed that the Company would not oppose a separate and properly designed rider. (T. 2287, 128)

The Commission agrees with Staff and AEEC that these charges should be recovered from ratepayers through a separate PCA rider[52] because these FERC-imposed charges are of a different nature than the costs included in the ECR rider.

Wholesale-Retail Allocations

EAI witness Schnitzer argues that in the initial year the approximately $284 million of the FERC-imposed charges should be allocated to EAI retail customers using a ninety-three percent (93%) energy allocation factor. (T. 2851-2862, 2866-2879, 2307-2308, T. Ex. 933-934) Mr. Schnitzer makes three arguments to support a 93% energy allocation factor.

First, according to Mr. Schnitzer, the reason for the FERC-imposed bandwidth remedy is the disparities in production costs among the Entergy Operating Companies ("EOCs"), and these recent disparities are driven primarily by increases in natural gas prices. Since the EOCs in Louisiana are more dependent upon natural gas plants, this increase in the price of natural gas has affected them disproportionately. Consequently, EAI's bandwidth payments are caused by an increase in the price of natural gas. (T. 2860-2861, 2868-2869)

Second, Mr. Schnitzer states that the amount that EAI will have to pay to other EOCs is solely attributable to EAI being below the system average in energy-related costs; EAI is above the system average in demand-related costs. Thus, to accomplish the

[52]The PCA amount shall appear on ratepayer bills as a separate line-item labeled "FERC Imposed Entergy System Agreement Production Cost Equalization Payment".

bandwidth remedy mandated by FERC, the only reason for the disparity is EAI's below-average energy costs. (T. 2870-2872)

Third, Mr. Schnitzer states that FERC has determined that these bandwidth payments should be included in Account 555 and flowed through Service Schedule MSS-3, which has been solely related to fuel and purchased power costs. (T. 2874-2876, T. Ex. 1347)

Staff witness Wright argues that the retail allocation should be set at 86.13%, which is the Production Demand Allocation Factor ("PDAF") established by the Commission in Docket No. 96-360-U. Ms. Wright argues that pursuant to a Settlement Agreement in that Docket, which was agreed to by EAI, the retail production demand allocator used in any future proceeding will never exceed 86.13%. According to Ms. Wright, this specific provision was included to protect retail ratepayers from additional production costs resulting from the loss of EAI wholesale load. (T. 2958-2960, 2969-2972, 2981-2983) Ms. Wright also states that the FERC-mandated bandwidth payments are not properly classified as energy since the differences between EAI's fuel mix and the other EOCs' fuel mixes are ultimately the direct result of the type and vintage of generation capacity owned by the companies. (T. 2989)

Additionally, Ms. Wright asserts that EAI, in Docket No. 03-028-U, proposed to protect retail ratepayers from any negative effects which might result from approval of the PPAs due to the operation of the ECR rider, the Grand Gulf rider, and the Arkansas Nuclear One decommissioning cost rider. According to Ms. Wright, the intent of these provisions is to protect retail ratepayers from additional costs associated with

jurisdictional allocation issues resulting from the approval of the PPAs and/or the loss of wholesale load. (T. 2960-2961, 2969-2972, 2983-2987)

AG witness Marcus recommends that the bandwidth payments be considered 50% energy-related and 50% demand-related for two reasons. First, the reason for the cost inequities among the EOCs is fuel mix and EAI's historical generation capacity. Second, the cost inequality arises from a combination of demand and energy costs on the various Companies. Mr. Marcus's recommendation is that 86.18% of these costs be allocated to retail. (T. 649-650)

AEEC witness Falkenberg recommends that the bandwidth payments be classified between fixed and variable in the same proportion as EAI's underlying average production costs. Using those factors Mr. Falkenberg recommends an 88.43% retail allocation factor. (T. 1846-1847)

Company witness Schnitzer responds to those proposals with a number of arguments. First, Mr. Schnitzer argues that any retail allocator less than 93% is inconsistent with the FERC decision because that would implicitly allocate part of EAI's bandwidth payments to the affiliated PPAs' loads. Further, such an approach would fail to move EAI's production costs to 89% of the system average. (T. 2852-2858)

Second, the cause of EAI's bandwidth payments is the recent increase in natural gas prices, which disproportionately affect the Louisiana companies. (T. 2859-2860)

Third, the FERC used Service Schedule MSS-3, an energy-related rate schedule, for purposes of flowing through bandwidth payments and receipts among the EOCs. (T. 2861)

Fourth, Mr. Schnitzer argues that the amount that EAI has to pay is solely attributable to EAI's being below the system average in energy-related costs; EAI is above the system average in demand-related costs. (T. 2870-2872)

Fifth, Mr. Schnitzer states that since these bandwidth costs were not addressed in the 96-360-U Settlement, the PDAF factor is not applicable in this instance. (T. 156-158, 169-173)

Finally, Mr. Schnitzer argues that the retail protection mechanisms in Docket No. 03-028-U are not applicable here. (T. 161-162, 174-177)

The two primary reasons for EAI now being required to make payments under the bandwidth approach are the significant decreases in the net plant book values of EAI's expensive nuclear and coal plants since the 1980's because of accumulated depreciation and the recent run-ups in natural gas prices. Since the bandwidth calculations focus on the most recent prior year, the amount of fixed costs, then, is relatively small, while the variable costs are relatively high, caused by high natural gas prices. This means that the primary remaining cause of the bandwidth payments is the recent increases in natural gas prices. That means that the bandwidth payments are predominately energy-related and consequently the PDAF factor does not apply.

Staff's arguments regarding the retail protections provided in Docket No. 03-028-U are misplaced. The retail protections from that docket concern negative impacts flowing from the sale of the EAI baseload units through the PPAs. The sale of those units did not cause the loss in wholesale load. The direction of causation is exactly opposite: It is the loss of wholesale load, specifically the North Little Rock load, which opened up the possibility of the PPAs. Consequently, the reason that the retail

allocation factor has increased is not because of the 03-028-U PPAs *per se*, but because of the loss in wholesale load as EAI's wholesale contracts expire.

The only record evidence of the appropriate retail energy factor is shown in EAI Exhibit PBG-13. (T. 933-934) The retail allocation derived from that exhibit is 92.13%, and that is the retail allocation factor to be used here. Until EAI leaves the System Agreement in 2013, in future PCA filings a similarly appropriate retail energy allocation factor should be used, unless it can be shown that the bandwidth payments are not energy-related. Because of our decision on this issue, the EAI retail allocations of the bandwidth payments will also be based on a 93% retail energy allocator.

Other PCA Rider Issues

EAI witness Gillam proposes that a carrying charge be applied to any under- or over-recoveries during the PCA rider year. (T. 2259-2261) The FERC has ordered that EAI's bandwidth payments, based on the year 2006 production costs, will be made over a seven-month period, June through December of 2007. This will be true in the following years as well. EAI proposes that its bandwidth payments be recovered from retail ratepayers over a twelve-month period. According to Mr. Gillam, this will significantly and consistently result in EAI making payments prior to the rate recovery of such payments from Arkansas retail ratepayers. (T. 2288-2290, 2308-2309, T. Ex. 909-910) Mr. Gillam argues that this consistent result is analogous to working capital because of the revenue lag. (T. 2308-2309)

Staff witness Wright responds by stating that a lag in a rate rider such as the PCA does not necessitate a carrying charge. Any lag in the collection of the bandwidth payments could be mitigated by excess earnings as a result of sales growth and

depreciation of existing plant over time. Ms. Wright recommends that the proper treatment of any over-or under-recovery balance should be determined closer to the time when EAI exits the Entergy system agreement and based on the circumstances at that time. (T. 2992-2994)

Because of the extremely unusual manner in which FERC has ordered the bandwidth payments be made (over seven months instead of twelve months), EAI's proposed retail recovery over twelve months will consistently result in an under-recovery. For this reason, the Commission finds that it is appropriate to allow EAI a carrying charge equal to the customer deposit interest rate in the context of an annual true-up adjustment for differences between projected sales and actual sales during the recovery year.

Thus, the calculations will be performed in the following steps:

(1) Allocate the FERC-imposed payment to retail rate classes based on the annual energy class allocators;

(2) Determine the class-specific kwh rate by dividing the class-specific FERC-imposed payment by that class's projected annual energy usage during the billing year;

(3) For each rate class and each billing month in the twelve-month period ending with the last day of February in the billing year, accumulate over- and or under recoveries using: (a) the difference between actual class recovery and actual retail payment of the FERC-imposed payment (using the energy allocator for that class); and (b) apply a monthly carrying charge for each class and for each month to the end of the twelve-month period referred to above; and

(4) Sum the over- and over-recoveries with accumulated carrying charges for each class during the twelve-month period ending in February and apply that as a true-up adjustment to be applied to the corresponding class in the following year's annual redetermination.

Additionally, the threshold for an interim adjustment will be 55% of the FERC bandwidth payment included in the most recently filed rate determination under the PCA rider. Seasonal rates are not appropriate for the PCA since the FERC-imposed costs are not seasonal, but fixed monthly over a seven-month period in each calendar year.

The Commission also clarifies that this PCA rider does not include refunds that the FERC may possibly order to be paid by EAI to the other EOCs in FERC Docket No. EL01-88-000. If refunds are ordered by the FERC, EAI must file a separate request to ask for retail recovery of such refund.

Optional Irrigation Control Service Rider - M25

Staff witness Bradley testifies that EAI is proposing the elimination of its Optional Irrigation Control Service Rider, or Rider M25, ("Irrigation Rider"), a rider designed to give irrigation customers a credit for allowing EAI to control the operation of irrigation pumps during periods of curtailment. Ms. Bradley testifies that there were approximately 2,200 customers participating in the program in 2005 and 2006. (T. 3284) Ms. Bradley notes that EAI proposes to eliminate the Irrigation Rider because the control equipment is no longer functional and is not repairable and that, based on the results of the Ratepayer Impact Measure ("RIM") test, continuation of the program is no longer economic. (T. 3285) Ms. Bradley, however, recommends that the program continue because of: the negative impact abrupt cessation would have on over 2,000

customers; her ongoing concern that the RIM test results are not accurate; and the possible hindrance that cessation of the program would have on the Commission's conservation and energy efficiency initiatives of Docket No. 06-004-R.[53] (T. 3285, 3305) Ms. Bradley also asserts that, with certain corrections to the RIM test as well as some changes to the provisions of the tariff, the program could be found economically viable. (T. 3285-3286, 3305)

EAI witness Cooper testifies that he has calculated the RIM test using both his original five year payback period and, in response to Ms. Bradley's concerns, a ten year pay back period, both of which continue to reflect that continuation of the program is not economic. (T. 2343-2344) EAI witness Castleberry testifies that the equipment to control the irrigation pumps has been removed and that EAI no longer has control over the pumps at peak. Thus, Mr. Castleberry continues, should the Irrigation Rider credit remain in place, the reduced rates to these customers will be subsidized by all other customers. (T. 1603) The cost of that subsidy, according to Mr. Castleberry, is approximately $771,068.

The Commission approves the discontinuation of the program in view of the subsidy provided this service by other ratepayers. The Commission finds that the program can no longer be offered economically, given both the RIM test results and the disappointing fact that the older equipment has been removed and cannot be used to reinstate pump control. During the hearing it became apparent to the Commission that while the equipment is no longer usable, because the Company did not maintain the equipment in working order. This is unfortunate given that similar programs are used

[53]In the Matter of a Notice of Inquiry Regarding a Rulemaking for Developing and Implementing Energy Efficiency Programs.

by the electric cooperatives in Arkansas to the benefit of both the customer and the cooperatives.[54] Given the importance that the Commission is placing on demand response and energy efficiency measures in Docket No. 06-004-R, the Commission directs EAI to investigate reinstatement of this program as its BPL pilot project progresses and that EAI address this service in the context of any conservation or efficiency initiatives it may propose.

Master Metering Exemption - GSR 5.20

Ms. Bradley recommends EAI's exemption to General Service Rule ("GSR") 5.20, Master Metering, be rescinded. Ms. Bradley asserts that EAI failed to properly satisfy the Rule's provisions related to a prior application by EAI to replace multiple meters with a single meter. Ms. Bradley testifies that EAI has not appropriately provided the explanations required under Section C of the Rule. (T. 3286, 3307-3309) In response, EAI witness Meyer indicates that EAI is opposed to the rescission. (T. 2586) Ms. Bradley, although recommending rescission, also recommends that customers currently served under the exemption be grand-fathered under EAI's prior service, until such time EAI files for and receives exemption. (T. 3309)

The Commission finds, based on Ms. Bradley's description of EAI's application process, that EAI has failed to comply with the requirements under General Service Rule 5.20 and hereby rescinds EAI's exemption to this rule but reserves the exemption applicable to customers it currently serves under that exemption.

[54]Presentation by Arkansas Electric Cooperative Corporation ("AECC"), May 25, 2007, and comments filed in Docket No. 06-004-R by AECC.

Extension of Facilities and Underground Extension
("EOFP" & "UGP") and Meter Charge

AG witness Marcus recommends changes to EAI's amended line extension policies, Rate Schedule No. 60, Extension of Facilities Policy ("Line Extension Policy") and Rate Schedule No. 61, Tariff Governing The Installation Of Electric Underground Residential Distribution Systems and Underground Service Connections ("Underground Policy"). Mr. Marcus proposes that the calculation which sets the basis for the number of feet provided to customers at no cost - 800 feet in EAI's proposal – be corrected. Mr. Marcus testifies that EAI erroneously established that footage based on a payback period from estimated sales at the new location using the entire bundled rate, rather than just the distribution portion of the rate. Mr. Marcus asserts that this error will result in other ratepayers subsidizing line extensions, particularly to developers. (T. 731-737) When calculated based on the distribution function alone, Mr. Marcus continues, customers would receive only 218 feet at no cost. (T. 735) However, to prevent significant costs to new rural customers taking overhead service, Mr. Marcus testifies that he will accept the 800 feet allowed in the Line Extension Policy. However, with regard to the Underground Policy, Mr. Marcus recommends that base overhead footage be limited to 300 feet. Mr. Marcus assets this is necessary to avoid significant subsidy to developers, who are more likely to opt for underground lines. In conjunction with that limitation, Mr. Marcus recommends that EAI directly charge these customers for meters, rather than include the costs in base rates, noting that this small change will more appropriately balance the interest of developers with the interest of ratepayers. (T. 736-737)

EAI witness Grillo and Staff witness Cotten do not support Mr. Marcus' proposed amendments to the revised tariffs nor do they support separately charging for meters. Mr. Grillo testifies that EAI's originally proposed tariff provisions are cost justified, with the Underground Policy appropriately charging for any differential costs. Both Mr. Cotten and Mr. Grillo testify that the proposed payback calculation used to set the allowed footage in the amended tariffs is no different than that in EAI's current tariffs. Mr. Grillo and Mr. Cotton therefore recommend that the Commission reject Mr. Marcus' changes and his proposal to separately charge for meters and approve the tariffs as recommended by Mr. Cotten. (T. 1088-1091, 1713-1715, 1728-1730)

The Commission finds, for purposes of calculating the pertinent payback period, that limiting the revenue stream to the distribution-only, unbundled portion of the tariff is not appropriate. New customers will contribute incrementally based on collection of the entire bundled rate, and Mr. Marcus does not establish in the record sufficient justification or need for a change from the currently approved methodology. The Commission therefore rejects those proposed changes and adopts both the Line Extension Policy and the Underground Policy as recommended by Staff witness Cotten.

Annual Earnings Review

Under applicable Arkansas law the Company is entitled in this case to a timely final order establishing a prospective retail revenue requirement and appropriate retail rates and tariffs to be effective as of June 15, 2007. Such prospective revenue requirement, rates and tariffs must satisfy the requirements of Arkansas law and fall within the regulatory ratemaking parameters established by the United States Supreme

Court in the Hope and Bluefield cases.[55] The Commission's findings in this order regarding the Company's prospective revenue requirement, rates and tariffs are based upon substantial evidence of record and are just and reasonable. Therefore, such findings are in compliance with both Arkansas and federal law.

However, there are no state or federal legal requirements that require this Commission to approve the Company's proposed Production Costs Adjustment rider[56] ("PCA") or its proposed Capacity Management rider ("CM"). Nor are there any state or federal legal requirements that require this Commission to approve the continuance of the Company's Energy Cost Recovery rider ("ECR"). Clearly the Company is legally entitled to a just and reasonable retail revenue requirement and rates and tariffs that allow the Company the opportunity to recover its prudently incurred public utility operating expenses and to earn a fair return on its capital investment dedicated to the public use. Such revenue requirement must fairly comprehend, among other elements, the Company's prudently incurred costs for energy and fuel expenses as well as for historic and/or new electric generation capacity and associated plant prudently acquired, installed and operated for the public use in furtherance of the Company's public utility obligations.[57] However, the Company is not legally entitled to recover such

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[55]*Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Water Works & Improvement Co. v. Public Sservice Commission of West Virginia*, 262 U.S. 679 (1923)

[56]The Commission does not concede that the Company is entitled to immediate recover from its ratepayers of the System Agreement payments which the Federal Energy Regulatory Commission ("FERC") has ordered it to make to its affiliated operating companies. Further, this Commission continues to pursue its appeal of the FERC's System Agreement orders in the federal courts.

[57]The Commission notes that Entergy Services, Inc., has made a filing with the FERC in Docket No. ER07-93-000 seeking to include in its Open Access Transmission Tariff ("OATT") those costs related to Entergy's unsuccessful efforts to join or form a Regional Transmission Organization ("RTO"). This FERC proceeding has been the subject of ongoing settlement processes at the FERC. This Commission specifically reserves judgment on all issues concerning such costs in any future proceedings before this

costs through automatic riders, such as the PCA, the CM, and the ECR. Under Arkansas law the Commission could require that costs associated with the Company's PCA, the CM, and the ECR be recovered through the normal rate case processes available to the Company.

Though not legally obligated to do so, the Commission has determined herein that conditional approval of the PCA and conditional continuance of the ECR are in the public interest. However, the Commission has determined that approval of the CM is premature and not in the public interest and, therefore, has rejected the CM for the reasons cited elsewhere.

The PCA and the ECR, as modified hereinabove, are approved for a limited-time trial period to end on December 31, 2008, unless expressly authorized by the Commission to be continued beyond December 31, 2008, and subject to the development and implementation of an annual earnings review process ("AER") for the Company. The Commission directs the parties to expeditiously develop and file a proposed AER process for the Commission's consideration. The AER should be designed to be fair and reasonable for both ratepayers and the Company and should comprehend prudently incurred substantial changes to the Company's financial circumstances occurring during the course of the review year, including but not limited to the acquisition by the Company of additional electric generation resources and associated plant as pre-authorized by the Commission. Another objective of the AER shall be to capture any excess earnings above the revenue requirement authorized herein and to credit such excess earnings to the benefit of ratepayers through the PCR. The

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Commission examining whether EAI's retail rates are just and reasonable, including the AER process to be developed pursuant to this Order.

Commission envisions an AER process similar to the Regulatory Earnings Review Tariff ("RERT") approved for the Company in Commission Docket No. 98-114-U.[58] However, in the development of the proposed AER, the parties are not obligated to strictly duplicate the RERT process.

The Commission is of the opinion that the proposed AER process can be developed by the parties and submitted for the Commission's consideration and approval within a relatively short period of time, especially if the RERT process is used as the model for the AER. Accordingly, the parties are directed to file the proposed AER process within sixty days of the date of this Order. Allowing for an appropriate procedural schedule for consideration of the proposed AER process, the Commission would hope to approve an acceptable AER to be effective as of July 1, 2007, within 60 to 90 days of the date of filing the AER process.[59]

Assuming an acceptable AER process can be implemented effective July 1, 2007; the Commission will allow the PCA and the ECR to remain in effect until December 31, 2008. Prior to the sunset of the PCA and the ECR on December 31, 2008, the Commission will consider whether such riders should be allowed to continue for calendar year 2009. The Commission's decision to allow the riders to continue for calendar year 2009 will be substantially influenced by the Company's progress towards the development and approval of an amended Entergy System Agreement acceptable to this Commission and the continued effectiveness of the Company's December 19, 2005, Notice to Withdraw from the Entergy System Agreement.

[58]The RERT was approved by the Commission in Order No. 3.

Uncontested Issues

The Commissions finds that the Amended Issues List also delineates those issues upon which the parties have reached agreement. The Commission has considered the record on the issues for which agreement has been reached and finds substantial evidence within the record for the final positions taken. Therefore, for those issues upon which the parties agree, the Commission approves those positions and rate treatment as outlined within the Amended Issues List filed April 23, 2007.

Conclusion

1. Revised retail rates and tariffs in compliance with this Order shall be effective for all electric usage on and after June 15, 2007.

2. EAI shall file with the Commission such revised retail rates and tariffs for review and approval as expeditiously as possible.

3. EAI shall otherwise fully comply with the directives set forth in this Order.

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[59]The Commission recognizes that the first earnings review under the AER will cover only 6 months, i.e., July 1, 2007 through December 31, 2007. The second earnings review will cover calendar year 2008.

BY ORDER OF THE COMMISSION.

This 15th day of June, 2007.

Paul Suskie, Chairman

Sandra L. Hochstetter, Commissioner

Daryl Bassett, Commissioner

Diana K. Wilson
Secretary of the Commission

I hereby certify that the following order issued by the Arkansas Public Service Commission has been served on all parties of record this date by U.S. mail with postage prepaid, using the address of each party as indicated in the official docket file.

Diana K. Wilson
Secretary of the Commission
Date 6/15/07

EXHIBIT
S-35
Admitted

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UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.43 Edison Electric Institute (EEI) dues.

a. Refer to Mr. Dukes' rebuttal testimony at page 18, lines 9 and 10. Please quantify and explain fully and in detail exactly how "...lobbying expense probably benefits customers just as much or even more than shareholders."

b. Is Mr. Dukes advocating that lobbying expense be included in rates? If not, explain fully why not.

c. Does UNS Electric record its directly incurred lobbying expense in a below-the-line account? If not, explain fully why not.

d. Other than the lobbying cost included in the EEI dues, has UNS Electric included any other lobbying expense in test year operating expenses? If so, please identify the amounts by account. If not, please explain fully why not.

RESPONSE:

a. This is quantified in Mr. Dukes' Rebuttal Testimony on page 18, lines 12 through 18.

b. Mr. Dukes is not advocating that lobbying expense be included in the rates in this case.

c. Yes, when identified.

d. Not that UNS Electric is aware of.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

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S-36
Admitted

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.44 Edison Electric Institute (EEI) dues. . Refer to Mr. Dukes' rebuttal testimony at pages 17 and 18.

a. Does Mr. Dukes agree that the NARUC-designated categorization of EEI expenditures for the year ended December 31, 2005 from which Mr. Smith derived the 49.93 percent disallowance for EEI Core Dues is factual? If not, explain fully why not.

b. Does UNS Electric have a more recent NARUC-designated categorization of EEI expenditures than the one referenced in part a above? If so, please provide it. If not, explain fully why not.

c. Is it Mr. Dukes' understanding that NARUC-designated categorizations of EEI expenditures are intended to identify disallowable costs in addition to lobbying costs and payments to influence legislation? If not, explain fully why not.

d. Please explain Mr. Dukes' complete understanding of the purpose of the NARUC-designated categorization of EEI expenditures.

RESPONSE:

a. Mr. Dukes did not attempt to verify the 49.93% to source documentation beyond the workpaper provided by Mr. Smith.

b. No. The Company has not attempted to obtain that specific information from NARUC.

c. No. It is Mr. Dukes' understanding that the categorizations provided by NARUC are provided for informational purposes. It is up to each individual Commission to determine whether any costs should be disallowed or not.

d. Mr. Dukes' understanding is that it is formulated to provide information that can be used by Commission in their evaluation of the recoverability of EEI dues if the individual Commission chooses to rely upon it.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

EXHIBIT
S-37
Armstrong

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Rate Case Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 5, 2006
PREPARED BY:	Janet Zaidenberg-Schrum JZS
CHECKED BY:	Dallas Dukes
REVIEWED BY:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
928	Regulatory Expense	$200,000	
	ENTRY TOTAL	$200,000	$0

Reason for Adjustment

To include an estimate of outside expenditures for the rate case expense amortization (expense is estimated at $600,000 to be amortized over 3 years).

Not confidential

EXHIBIT
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S-38
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UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO
RUCO'S FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 15, 2007

1.06 Rate Case Expense Please provide the following information regarding rate case expense:

a) What amount of proforma rate case expense is the Company requesting in this docket?

b) How much rate case expense is embedded in the actual test year and in what account?

c) How much rate case expense does the Company expect to incur associated with this docket?

d) How long does the Company anticipate the rates set in this docket will be in effect?

e) Identify each item of rate case expense incurred to date and provide supporting documentation; and

f) Provide monthly updates.

RESPONSE:

a) The Company is requesting the recovery of all prudently incurred outside costs directly related to the conduct of this rate case. The Company has included an estimate of $600,000 in rate case expense to be recovered over a three-year amortization period.

b) There is no rate case expense embedded in the actual test year.

c) The Company has not revised its estimate of $600,000 at this time.

d) The Company anticipates the rates set in this docket will be in effect for three years.

e) Attached as Bates Nos. UNSE(0783)00332 to UNSE(0783)00389 are detail and supporting documentation for each item of rate case expense incurred to date. Bates Nos. UNSE(0783)00332 to UNSE(0783)00389 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

f) Monthly updates of rate case expense revisions will be provided when applicable.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

Not Confidential

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO
RUCO'S FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 15, 2007

SUPPLEMENTAL RESPONSE: f) Please see RUCO 1.06 (Feb 07 thru May 07), Bates Nos. UNSE(0783)09967 to UNSE(0783)09982 for the applicable monthly updates.

Bates Nos. UNSE(0783)09967 to UNSE(0783)09982 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

SECOND SUPPLEMENTAL RESPONSE: f) Please see RUCO 1.06 (June 07), Bates Nos. UNSE(0783)10451 to UNSE(0783)10454 for the June update.

Bates Nos. UNSE(0783)10451 to UNSE(0783)10454 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

THIRD SUPPLEMENTAL RESPONSE: f) Please see RUCO 1.06 (July 07), Bates Nos. UNSE(0783)10455 to UNSE(0783)10460 for the June update.

Bates Nos. UNSE(0783)10455 to UNSE(0783)10460 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

Not Confidential

UNS Electric Rate Case Expense
Costs incurred April 2006 - July 2007

TEP Labor	$ 282,568
TEP Labor Taxes	$ 16,174
TEP Labor Loads	$ 128,978
Other Outside Services	$ 202,246
	$ 629,966 A

Update for July 2007

Not Confidential

UNS Electric Rate Case Expense
Costs incurred July 2007

TEP Labor	$	34,317
TEP Labor Taxes	$	2,190
TEP Labor Loads	$	15,027
Other Outside Services	$	(3,705)
	$	47,828

2A

BALANCE QUERY
File: Balance Sheet: Acct, Subacct
Period Name: JUL-07
Run Date: 06-AUG-07

Co: 033

Date	Account	Account Title	Sub	Sub Title	Begin Bal	Debits	Credits	Period Net	Balance
JUL-07	18390	Other Deferred Debits	0000	Unspecified	582,138.14	62,445.74	14,617.87	47,827.87	629,966.01
Sum					582,138.14	62,445.74	14,617.87	47,827.87	629,966.01

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2A

Not Confidential

CONFIDENTIAL- UNSE(0783)10457

Transaction Detail
All Sources
GL Period: JUL-07 Name, Co: 033mpany, Account: 18390, Subaccount: 0000, Co: 033st Center, &Task, &Expenditure Type, &Project Number, &Location, &Activity, &Business Center, &Cash Type, &Service Product Code, &FERC Account

Co: 033 | GL Period: JUL-07

Acct	Sub Acct	Query Source	GL Je Source	Task Number	PA Transaction Source	PA Expenditure Type Comment	GL JE Name	DR	CR	Net Amount	Vendor Name	Inv #
18390	0000	Projects		UNE06RC	Peoplesoft Expenses	FUTA Debit		0.37		0.37	Taxes	
18390	0000	Projects		UNE06RC	Peoplesoft Expenses	Gross Pay		34,329.25		34,329.25		
18390	0000	Projects		UNE06RC	Peoplesoft Reversal	Gross Pay Reversal			12.57	<12.57>	LABOR	
18390	0000	Projects		UNE06RC	Peoplesoft Expenses	Med Tax ER		452.24		452.24		
18390	0000	Projects		UNE06RC	Peoplesoft Reversal	Med Tax Reversal			0.13	<0.13>		
18390	0000	Projects		UNE06RC	Peoplesoft Expenses	SS Tax ER		1,737.44		1,737.44		
18390	0000	Projects		UNE06RC	Peoplesoft Reversal	SS Tax Reversal			0.56	<0.56>	Taxes	
18390	0000	Projects		UNE06RC	Peoplesoft Expenses	SUTA Debit		0.19		0.19		
18390	0000	Projects		UNE06RC	Peoplesoft Expenses	Work Comp Debit		27.47		27.47		
18390	0000	Projects		UNE06RC	Peoplesoft Reversal	Work Comp Reversal			0.01	<0.01>	Loads	
18390	0000	General Ledger	Spreadsheet				J342 A/P Accrual Adjustment L		9,998.43	<9,998.43>		
18390	0000	Payables		UNE06RC			Purchase Invoices USD	9,998.43		9,998.43	FOSTER ASSOCIATES INC 3A	1149
18390	0000	Payables		UNE06RC			Purchase Invoices USD	895.00		895.00	SUMMIT BLUE CONSULTING LLC 4A	100521
18390	0000	Purchasing	Purchasing				Reverses "Accrual USD JUL-0		4,600.00	<4,600.00>	Other	
18390	0000	Projects		UNE06RC	BURDENS			14,999.18		14,999.18	Loads	
Sum Total								62,439.57	14,611.70	47,827.87		
								62,439.57	14,611.70	47,827.87 A		

Not

TEP LABOR = 34,316.68
TEP Labor taxes = 2,189.55
TEP " loads = 15,026.64
Other outside Services = <3,705.00>
47,827.87

Not Confidential

CONFIDENTIAL- UNSE(0783)10458

2

EXHIBIT
S-40
Admitted

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.57 Refer to Mr. Dukes' rebuttal at pages 19-20.

a. Please identify all "new" information on test year overtime expense that was not available to UNS Electric when Mr. Dukes filed his direct testimony.

b. Please confirm Mr. Dukes' understanding that in the UNS Gas case, Staff's witness Mr. Smith presented two alternative calculations of normalized overtime expense; however, in his rebuttal in the UNS Electric case, Mr. Dukes failed to consider the results under both calculations. If this cannot be confirmed, explain fully why not.

c. Please confirm that if Mr. Dukes had used the alternative calculations of normalized overtime expense, the result would a decrease, not an increase.

RESPONSE:

a. The Staff's position on the calculation of overtime in the UNS Gas, Inc. ("UNS Gas") case was received and accepted.

b. Mr. Dukes used the calculation that was supported by the Staff in the UNS Gas case and accepted by UNS Gas as the most representative of expected results. Mr. Dukes did not perform any other calculations beyond his originally filed methodology.

c. Mr. Dukes did not perform any alternative calculations.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

EXHIBIT
S-41
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UNS ELECTRIC, INC.'s RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 14, 2007

STF 11.1 Refer to the supplemental response to STF 3.83.

a. Please provide each specific goal for the PEP for 2004, 2005 and 2006 and provide the actual achieved performance for each year related to each such goal.

b. In what account did UNS Electric record the SERP expense in STF 3.83 part b?

c. In what account did UNS Electric record each of the retirement plan expenses in STF 3.83 part c?

d. Explain why there is a cost to UNS Electric for the deferred comp plan.

e. Does the cost to UNS Electric for the deferred comp plan relate entirely to the additional matching contribution for compensation in excess of the legal limitation on 401(k)-plan eligible compensation? If not, please identify, quantify and explain what else is causing the expense to UNS Electric for the deferred comp plan.

f. Is there a separate cost to UNS Electric for the "401(k) Excess Company Match"? If so, please identify, quantify and explain how UNS Electric accounted for such expense in the test year.

g. In what account did UNS Electric record the expense for Officer's Long-term Incentive compensation mentioned in response to STF 3.83 part h?

h. Is the "TEP Excess Benefit Plan" identical to the SERP? If not, please identify, quantify and explain how UNS Electric accounted for all expenses in the test year related to the TEP Excess Benefit Plan.

i. The supplemental response indicates that for the PEP, the targeted bonus percentages are based on a percent of salary base, with different ranges for regular non-union employees and for Managers and Officers. Please breakout the test year expense that UNS Electric is requesting for PEP by account to separately identify the portions related to (1) regular non-union employees and (2) Managers and Officers. If exact amounts are not available, provide the Company's best estimates and show in detail how such estimates were derived.

UNS ELECTRIC, INC.'s RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 14, 2007

RESPONSE:

a. PEP 2004 - Please see STF 11.1 (a) (2004 PEP UES-E Final Results) on the enclosed CD for specific goals and actual achieved performance. The Excel file on the enclosed CD is not identified by Bates numbers. Also, STF 11.1(a) contains confidential information and is being provided pursuant to the terms of the Protective Agreement.

PEP 2005 - Please see STF 11.1 (a) (2005 PEP UES-E Final Results) for specific goals and actual achieved performance. Note that the financial trigger in 2005 was not met, and therefore, PEP was not paid in 2005 as previously stated in response 3.83 (e). The Excel file on the enclosed CD is not identified by Bates numbers. Also, STF 11.1 (a) (2005) contains confidential information and is being provided pursuant to the term of the Protective Agreement.

PEP 2006: Refer to previously submitted data response 3.83 (e) for specific goals and actual achieved performance for PEP 2006.

b. The SERP expense in STF 3.83 (b) was recorded in FERC 923.

c. The retirement plan expenses in STF 3.83 (c) were recorded in the following accounts:

UNS Electric Pension	$	230,361	FERC 926
UNS Electric 401(k)	$	73,112	FERC 926
TEP Pension/401(k) Charged to UNS Electric	$	148,391	FERC 923
	$	86,405	FERC 926
UNS Gas Pension/401(k) Charged to UNS Electric	$	2,190	FERC 926
Deferred Compensation Plan	$	1,658	FERC 920
	$	7,377	FERC 923
Total	$	549,494	

d. The deferred compensation expense charged to UNS Electric consists of both the excess 401(k) matching contributions for officers (allocated to UNS Electric using the Massachusetts Formula) and the change in market value of the deferred compensation plan balances related to Thomas Ferry, Vice President and General Manager of UNS Electric (100% allocated to UNS Electric) and Dennis Nelson, Senior Vice President of UniSource Energy Services (allocated 50% to UNS Electric and 50% to UNS Gas).

e. As mentioned in d. above, the deferred compensation expense charged to UNS Electric consists of both the 401(k) excess matching contributions for officers and the change in market value of the deferred compensation plan balances for Thomas Ferry and Dennis Nelson. The dollar amounts charged to UNS Electric during the test-year are as follows:

Excess 401(k) Matching Contributions	$ 1,594
Change in Market Value of Plan Balances	$ 7,441
Total	$ 9,035

f. See response to e. above.

g. The Officer's Long-term Incentive compensation expense mentioned in response to STF 3.83.h. was recorded in FERC 923.

h. The "TEP Excess Benefit Plan" is the same as the SERP.

i. Test year expense that UNS Electric is requesting for PEP is as follows: (1) regular non-union employees and Manager - $ 98,247 and (2) Officers - $61,493.

RESPONDENT: Michael Daranyi (a)
Amy Teller (b, c, d, e, f and g)
HR Services Group (h and i)

WITNESS: Karen Kissinger (b, c, d, e, f and g)
Dallas Dukes (a, h and i)

EXHIBIT
ALL-STATE LEGAL®
S-42
Admitted

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTY-FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 24, 2007

STF 21.4 Refer to Mr. Dukes' rebuttal testimony at page 8, lines 13-16 and to Exhibit DJD-3.

a. What specific figures on Exhibit DJD-3 did Mr. Dukes' use. Please specify exactly where those figures are located on the exhibit.

b. Are all of the positions listed on Exhibit DJD-3 recipients of PEP? If not, please identify exactly which positions on Exhibit DJD-3 receive PEP awards.

c. If there is no amount in the "TTC" column on Exhibit DJD-3, does that mean that there is no "target annual incentive" for the position? If not, explain exactly what the blanks in the "TTC" column under "TEP Avg. Current" mean.

d. How much of the Company's requested test year PEP expense relates to PEP awards to employees whose base salaries exceed the "Market 50th Percentile"? Show detailed calculations.

e. Do TEP executives receive PEP?

f. Please identify how much of the Company's requested test year PEP expense relates to PEP awards to TEP executives. Show detailed calculations.

RESPONSE:

a. Page 3 of 10, of Exhibit DJD-3.

b. All positions listed on Exhibit DJD-3 are eligible to receive PEP.

c. If there is no amount in the "TTC" column on Exhibit DJD-3 that means that the "target annual incentive" was not communicated to Towers Perrin HR Services Consulting firm in advance of the study. Those positions are non-exempt and the "target annual incentive" is 3% of base salary.

d. There are two UNS Electric positions identified in Exhibit DJD-3 that were listed above "Market 50th Percentile." See calculations below for description of PEP expense as it relates to their pay in the year of the study that exceeds "Market 50th Percentile".

Supt, Plant- Nogales- NG043- Salary which exceeds 50th Percentile = $1,900 X 7% target bonus =$ 133.00 in estimated PEP expense over Market 50th Percentile.

District Engineer- KB019- Salary which exceeds 50th Percentile = $1,400 X 9% target bonus =$ 126.00 in estimated PEP expense over Market 50th Percentile.

Please note that because Exhibit DJD-3 is the most recent market study, the calculations are based on the data provided for that study.

Also note that overall base wages for UNS Electric are 6% below Market 50th Percentile, overall Total Compensation is 11% below Market 50th Percentile and Total Target Compensation is 12% below Market 50th Percentile, therefore overall PEP expense requested should be <u>under</u> Market 50th Percentile by a corresponding percentage.

e. Yes.

f. $61,493. Please see STF 21.4 (f), Bates Nos. UNSE(0783)11672 to UNSE(0783)11686 , on the enclosed CD, which includes the supporting calculations for the PEP amount accrued during the test year related to TEP Officers.

RESPONDENTS: Human Resource Group and Dallas Dukes

WITNESS: Dallas Dukes

Query Source:General Ledger

GL Period	Co	Acct	Sub Acct	Gl Je Source	Gl JE Name	DR	CR	Net Amoun
ALL in FERC 923								
						Debit	Credit	Total
JUL-05	033	52100	0000	Spreadsheet	J28 Incentive Comp-Ucl Pensions & Benefits USD	9695	1a	9695
AUG-05	033	52100	0000	Spreadsheet	J28 Incentive Comp-Ucl Pensions & Benefits USD	9695	2a	9695
SEP-05	033	52100	0000	Spreadsheet	J28 Incentive Comp-Ucl Pensions & Benefits USD		8159 3a	-8159
OCT-05	033	52100	0000	Spreadsheet	J28 Incentive Comp-Ucl Pensions & Benefits USD	7711	4a	7711
NOV-05	033	52100	0000	Spreadsheet	J28 Incentive Comp-Ucl Pensions & Benefits USD	6518	5a	6518
DEC-05	033	52100	0000	Spreadsheet	J28 Incentive Comp-Ucl Pensions & Benefits USD	6518	6a	6518
DEC-05	033	52100	0000	Spreadsheet	J1028 Final PEP Adjustmen Pensions & Benefits USD		15298 7a	-15298
DEC-05	033	52100	0000	Spreadsheet	959 PEP Accrual Adjustmen Pensions & Benefits USD		26070 8a	-26070
JAN-06	033	52100	0000	Spreadsheet	J28 Incentive Comp-Ucl Pensions & Benefits USD	11813	9a	11813
FEB-06	033	52100	0000	Spreadsheet	J28 Incentive Comp-Ucl Pensions & Benefits USD	11814	10a	11814
MAR-06	033	52100	0000	Spreadsheet	J28 Incentive Comp-Ucl Pensions & Benefits USD	11814	11a	11814
APR-06	033	52100	0000	Spreadsheet	J28 Incentive Comp-Ucl Pensions & Benefits USD	11814	12a	11814
MAY-06	033	52100	0000	Spreadsheet	J28 Incentive Comp-Ucl Pensions & Benefits USD	11814	13a	11814
JUN-06	033	52100	0000	Spreadsheet	J28 Incentive Comp-Ucl Pensions & Benefits USD	11814	14a	11814
Total						111020	49527	61493
							check figure	61493

G:\RATES\UNS Elec Rate Case 2006\Data Requests\ACC\21st Set of Data Requests\[STF 21.6 UNSE Payroll Expense TME June 2007.xls]Payroll Adj Revised

Executive STIP charged to UNSE in test year

Tucson Electric Power Company
Unclassified Employees Incentive Compensation
J28
July-05

2-05 Per Michael Daranyi begin 2005 accruing @ 100%. This year we will break out officer from unclassified - change to expenditure type from 066 to 050 (UNC) and 052 (EXE). Business Center 006 (Other TEP) will not be allocated to.

8-2-05 Per discussion with Michael Daranyi, continue accruing PEP for July at 100%

	Summary	
Account 24000-3600		
Balance Required for 2005 PEP Accrual @ 7/31/05	3,235,750	(462,250) * 7
Mkt Dept. PEP - Paid in April	(7,040)	
Officer PEP (T. Delawder) - Paid in April	(13,875)	
Account 24000-3600 7/31/05 Balance - Preliminary	(2,752,585)	
Under / (Over) Accrual	462,250	$343,000 TEP Unclass + $107,500 TEP Exec + $11,750 UES Exec

Unclassified

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
UNSG	50.0%		0
UNSE	50.0%		0
	100.0%		0
Operation & Maintenance	100.0%	343,000	343,000
Construction & Removal	0.0%		0
	100.0%		343,000

Business Center

Operation & Maintenance Account Distribution		FERC Account (location)	* Loc Dist	Dist %	22.10% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	34.20% (003) Distribution	Dist %	43.70% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
					75,803		0		117,306		149,891		0	343,000	
Production		506 IV (300)	73.0%	42.25%	23,379		0	17.29%	20,281	0.54%	809		0	44,469	
		506 SC1 (314)	15.0%		4,804		0		0		0		0	4,804	
		506 SC2 (315)	12.0%		3,843		0		0		0		0	3,843	
Transmission		566			0		0	17.16%	20,130		0		0	20,130	
Distribution		588			0		0	23.81%	27,931	1.27%	1,904		0	29,835	
Customer Accounting & Service		903						7.52%	8,821	6.67%	9,996		0		
								7.42%	8,704	0.64%	959		0		
		903			0		0	14.94%	17,526	7.31%	10,957		0	28,483	Combine 903
Administrative & General		920		26.68%	20,224		0	18.13%	21,268	90.81%	136,116		0	177,608	
Production Maintenance		514 IVC (305)	33.0%	31.07%	7,772		0	0.08%	94		0		0	7,866	
		514 SC1 (314)	34.0%		8,008		0		0		0		0	8,008	
		514 SC2 (315)	33.0%		7,772		0		0		0		0	7,772	
Transmission Maintenance		570			0		0	2.97%	3,484	0.02%	30		0	3,514	
Distribution Maintenance		598			0		0	5.62%	6,593	0.04%	60		0	6,653	
Administrative & General Maintenance		935			0		0		0	0.01%	15		0	15	
Total Payroll	Total Operation & Maintenance				75,802		0		117,307		149,891		0	343,000	343,000
Construction & Removal - Acct. 79300														0	
	Total Allocation													343,000	

Officer

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
TEP (based on Mass. Formula beginning 2005)	77.62%		92,562
Millennium (based on Mass. Formula beginning 2005)	5.44%		6,487
UNSG (based on Mass. Formula beginning 2005)	8.81%		10,508
UNSE (based on Mass. Formula beginning 2005)	8.13%		9,695
	100.0%	119,250.00	119,250
Operation & Maintenance (TEP Only)	100.0%	92,562	92,562
Construction & Removal	0.0%		0
	100.0%		92,562

Business Center

Operation & Maintenance Account Distribution	FERC Account (location)	*	Dist %	14.40% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	12.60% (003) Distribution	Dist %	73.00% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
	TEP			13,329		0		11,663		67,570		0	92,562	
	500 - GEN			13,329		0		0		0		0	13,329	
	580 - UDC			0		0		11,663		0		0	11,663	
	920 - SSU			0		0		0		67,570		0	67,570	
Total Payroll				13,329		0		11,663		67,570		0	92,562	92,562
Total Allocation													92,562	

Account 21150-3306

Payroll Tax accrual required @ 7/31/05 for TEP PEP accrual	2,878,000	x	7.65%	=	220,167							
Preliminary Balance in A/C 21150 - 3306 (7/31/05)					(193,928)							
Under / (Over) Accrual					26,239							
			Unclassified		26,239		5,798	0	8,974	11,466	0	26,239
			Officer***		0		0	0	0	0	0	0
												26,239

FICA	7.65%	6.2% SS plus 1.45% Medicare
FUTA / SUTA	0.00%	Zero since not an incremental cost
WC	0.00%	Zero since not an incremental cost
	7.65%	

* Determined based on P/R by Function Report-Detail by Location for 2004
**See January 2005 journal for detailed back up of business center/distribution percentages
***Per L. Joyce stopped accruing Payroll Taxes on Officer portion in May-05

UNSE(0783)11673

Tucson Electric Power Company
Unclassified Employees Incentive Compensation
J28
August-05

2-05 Per Michael Daranyi begin 2005 accruing @ 100%. This year we will break out officer from unclassified - change to expenditure type from 086 to 050 (UNC) and 052 (EXE). Business Center 006 (Other TEP) will not be allocated to.

8-2-05 Per discussion with Michael Daranyi, continue accruing PEP for July at 100%

Account 24000-3600	Summary	
Balance Required for 2005 PEP Accrual @ 8/31/05	3,698,000	(462,250) * 8
Mkt Dept. PEP - Paid in April	(7,040)	
Mkt Dept. PEP - Paid in July	(21,039)	
Officer PEP (T. Delawder) - Paid in April	(13,875)	
Account 24000-3600 8/31/05 Balance - Preliminary	(3,193,796)	
Under / (Over) Accrual	462,250	$343,000 TEP Unclass + $107,500 TEP Exec + $11,750 UES Exec

Unclassified

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
UNSG	50.0%		0
UNSE	50.0%		0
	100.0%		0
Operation & Maintenance	100.0%	343,000	343,000
Construction & Removal	0.0%		0
	100.0%		343,000

Operation & Maintenance Account Distribution

	FERC Account (location)	* Loc Dist	Dist %	22.10% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	34.20% (003) Distribution	Dist %	43.70% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
				75,803		0		117,306		149,891		0	343,000	
Production	506 IV (300)	73.0%	42.25%	23,379		0	17.29%	20,281	0.54%	809		0	44,469	
	506 SC1 (314)	15.0%		4,804		0		0		0		0	4,804	
	506 SC2 (315)	12.0%		3,843		0		0		0		0	3,843	
Transmission	566			0		0	17.16%	20,130		0		0	20,130	
Distribution	588			0		0	23.81%	27,931	1.27%	1,904		0	29,835	
Customer Accounting & Service	903						7.92%	8,621	6.87%	9,898		0		
							7.42%	8,704	0.64%	999		0		
	903			0		0	14.94%	17,526	7.31%	10,957		0	28,483	Combine 903
Administrative & General	920		26.68%	20,224		0	18.13%	21,268	90.81%	136,116		0	177,608	
Production Maintenance	514 IVC (305)	33.0%	31.07%	7,772		0	0.08%	94		0		0	7,866	
	514 SC1 (314)	34.0%		8,008		0		0		0		0	8,008	
	514 SC2 (315)	33.0%		7,772		0		0		0		0	7,772	
Transmission Maintenance	570			0		0	2.97%	3,484	0.02%	30		0	3,514	
Distribution Maintenance	598			0		0	5.62%	6,593	0.04%	60		0	6,653	
Administrative & General Maintenance	935			0		0		0	0.01%	15		0	15	
Total Payroll — Total Operation & Maintenance				75,802		0		117,307		149,891		0	343,000	343,000
Construction & Removal - Acct. 79300													0	
Total Allocation													343,000	

Officer

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
TEP (based on Mass. Formula beginning 2005)	77.62%		92,562
Millennium (based on Mass. Formula beginning 2005)	5.44%		6,487
UNSG (based on Mass. Formula beginning 2005)	8.81%		10,506
UNSE (based on Mass. Formula beginning 2005)	8.13%		9,695
	100.0%	119,250.00	119,250
Operation & Maintenance (TEP Only)	100.0%	92,562	92,562
Construction & Removal	0.0%		0
	100.0%		92,562

Operation & Maintenance Account Distribution

	FERC Account (location)	*	Dist %	14.40% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	12.60% (003) Distribution	Dist %	73.00% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
	TEP			13,329		0		11,663		67,570		0	92,562	
	500 - GEN			13,329		0		0		0		0	13,329	
	580 - UDC			0		0		11,663		0		0	11,663	
	920 - SSU			0		0		0		67,570		0	67,570	
Total Payroll				13,329		0		11,663		67,570		0	92,562	92,562
Total Allocation													92,562	

Account 21150-3306

Payroll Tax accrual required @ 8/31/05 for TEP PEP accrual	3,221,000	x	7.65%	=	246,407						
Preliminary Balance in A/C 21150 - 3306 (8/31/05)					(215,479)						
Under / (Over) Accrual					30,928						
			Unclassified		30,928	6,835	0	10,577	13,516	0	30,928
			Officer***		0	0	0	0	0	0	0
											30,928

FICA	7.65%	6.2% SS plus 1.45% Medicare
FUTA / SUTA	0.00%	Zero since not an incremental cost
WC	0.00%	Zero since not an incremental cost
	7.65%	

* Determined based on P/R by Function Report-Detail by Location for 2004
**See January 2005 journal for detailed back up of business center/distribution percentages
***Per L. Joyce stopped accruing Payroll Taxes on Officer portion in May-05

UNSE(0783)11674

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Tucson Electric Power Company
Unclassified Employees Incentive Compensation
J28
~~August-05~~ Sept. '05

Account 24000-3600	Summary	
Balance Required for 2005 PEP Accrual @ 9/30/05	3,309,000	(367,666) * 9
Mkt Dept. PEP - Paid in April	(7,040)	
Mkt Dept. PEP - Paid in July	(21,039)	
Officer PEP (T. Delawder) - Paid in April	(13,875)	
Account 24000-3600 9/30/05 Balance - Preliminary	(3,656,046)	
Under / (Over) Accrual	(389,000)	*Adjusting entry this month to bring account down to new target amount.
		($288,647) TEP Unclass + ($90,465) TEP Exec + ($9,888) UES Exec

2-05 Per Michael Daranyi begin 2005 accruing @ 100%. This year we will break out officer from unclassified - change to expenditure type from 086 to 050 (UNC) and 052 (EXE). Business Center 006 (Other TEP) will not be allocated to.

8-2-05 Per discussion with Michael Daranyi, continue accruing PEP for July at 100%

10-05-05 Per e-mail from Michael Daranyi, adjust account for Annual total (both officers & Uncl) to $4,412,000.

Unclassified

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
UNSG	50.0%		0
UNSE	50.0%		0
	100.0%		0
Operation & Maintenance	100.0%	(288,647)	(288,647)
Construction & Removal	0.0%		0
	100.0%		(288,647)

Operation & Maintenance Account Distribution

		FERC Account (location)	Loc Dist	Dist %	22.10% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	34.20% (003) Distribution	Dist %	43.70% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
					(63,791)		0		(98,717)		(126,139)		0	(288,647)	
Production		506 IV (300)	73.0%	42.25%	(19,673)		0	17.29%	(17,088)	0.54%	(681)		0	(37,422)	
		506 SC1 (314)	15.0%		(4,043)		0		0		0		0	(4,043)	
		506 SC2 (315)	12.0%		(3,234)		0		0		0		0	(3,234)	
Transmission		566			0		0	17.16%	(16,940)		0		0	(16,940)	
Distribution		588			0		0	23.81%	(23,505)	1.27%	(1,602)		0	(25,107)	
Customer Accounting & Service		903						7.52%	(7,424)	6.87%	(8,413)		0		
								7.42%	(7,325)	0.64%	(807)		0		
		903			0		0	14.94%	(14,748)	7.31%	(9,221)		0	(23,969)	Combine 903
Administrative & General		920		26.68%	(17,019)		0	18.13%	(17,897)	90.81%	(114,547)		0	(149,463)	
Production Maintenance		514 IVC (305)	33.0%	31.07%	(6,541)		0	0.08%	(79)		0		0	(6,620)	
		514 SC1 (314)	34.0%		(6,739)		0		0		0		0	(6,739)	
		514 SC2 (315)	33.0%		(6,541)		0		0		0		0	(6,541)	
Transmission Maintenance		570			0		0	2.97%	(2,932)	0.02%	(25)		0	(2,957)	
Distribution Maintenance		598			0		0	5.62%	(5,548)	0.04%	(50)		0	(5,598)	
Administrative & General Maintenance		935			0		0		0	0.01%	(13)		0	(13)	
Total Payroll	Total Operation & Maintenance				(63,790)		0		(98,717)		(126,139)		0	(288,646)	(288,646)
Construction & Removal - Acct. 79300														0	
	Total Allocation													(288,646)	

Officer

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
TEP (based on Mass. Formula beginning 2005)	77.62%		(77,894)
Millennium (based on Mass. Formula beginning 2005)	5.44%		(5,459)
UNSG (based on Mass. Formula beginning 2005)	8.81%		(8,841)
UNSE (based on Mass. Formula beginning 2005)	8.13%		(8,159)
	100.0%	(100,353.00)	(100,353)
Operation & Maintenance (TEP Only)	100.0%	(77,894)	(77,894)
Construction & Removal	0.0%		0
	100.0%		(77,894)

Operation & Maintenance Account Distribution

	FERC Account (location)	Dist %	14.40% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	12.60% (003) Distribution	Dist %	73.00% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
	TEP		(11,217)		0		(9,815)		(56,863)		0	(77,895)	
	500 - GEN		(11,217)		0		0		0		0	(11,217)	
	580 - UDC		0		0		(9,815)		0		0	(9,815)	
	920 - SSU		0		0		0		(56,863)		0	(56,863)	
Total Payroll			(11,217)		0		(9,815)		(56,863)		0	(77,895)	(77,895)
Total Allocation												(77,895)	

~~Account 21150-3306~~

Payroll Tax accrual required @ 9/30/05 for TEP PEP accrual	2,932,353	x	7.65%	=	224,325							
Preliminary Balance in A/C 21150 - 3306 (9/30/05)					(243,760)							
Under / (Over) Accrual					(19,435)							
			Unclassified		(19,435)	(4,295)	0	(6,647)	(8,493)	0	(19,435)	
			Officer***		0	0	0	0	0	0	0	
											(19,435)	

FICA	7.65%	6.2% SS plus 1.45% Medicare
FUTA / SUTA	0.00%	Zero since not an incremental cost
WC	0.00%	Zero since not an incremental cost
	7.65%	

* Determined based on P/R by Function Report-Detail by Location for 2004
**See January 2005 journal for detailed back up of business center/distribution percentages
***Per L. Joyce stopped accruing Payroll Taxes on Officer portion in May-05

UNSE(0783)11675

3.

Tucson Electric Power Company
Unclassified Employees Incentive Compensation
J28
October-05

2-05 Per Michael Daranyi begin 2005 accruing @ 100%. This year we will break out officer from unclassified - change to expenditure type from 086 to 050 (UNC) and 052 (EXE). Business Center 006 (Other TEP) will not be allocated to.

8-2-05 Per discussion with Michael Daranyi, continue accruing PEP for July at 100%

10-05-05 Per e-mail from Michael Daranyi, adjust account for Annual total (both officers & Uncl) to $ 4,412,000.

Account 24000-3600	Summary	
Balance Required for 2005 PEP Accrual @ 10/31/05	3,676,667	(367,667) * 10
Mkt Dept. PEP - Paid in April	(7,040)	
Mkt Dept. PEP - Paid in July	(21,039)	
Officer PEP (T. Delawder) - Paid in April	(13,875)	
IS Admin - AG PEP - Paid in Sept	(7,500)	
Account 24000-3600 10/31/05 Balance - Preliminary	(3,259,546)	
Under / (Over) Accrual	367,667	

$272,817 TEP Unclass + $85,504 TEP Exec + $9,346 UES Exec

Unclassified

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
UNSG	50.0%		0
UNSE	50.0%		0
	100.0%		0
Operation & Maintenance	100.0%	272,817	272,817
Construction & Removal	0.0%		0
	100.0%		272,817

Business Center

Operation & Maintenance Account Distribution		FERC Account (location)	* Loc Dist	Dist %	22.10% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	34.20% (003) Distribution	Dist %	43.70% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
					60,293		0		93,303		119,221		0	272,817	
Production		506 IV (300)	73.0%	42.25%	18,896		0	17.29%	16,132	0.54%	644		0	35,371	
		506 SC1 (314)	15.0%		3,821		0		0		0		0	3,821	
		506 SC2 (315)	12.0%		3,057		0		0		0		0	3,057	
Transmission		566			0		0	17.16%	16,011		0		0	16,011	
Distribution		588			0		0	23.81%	22,215	1.27%	1,514		0	23,729	
Customer Accounting & Service		903						7.52%	7,016	6.67%	7,952		0		
								7.42%	6,923	0.64%	763		0		
		903			0		0	14.94%	13,939	7.31%	8,715		0	22,654	Combine 903
Administrative & General		920		26.68%	16,086		0	18.13%	16,916	90.81%	108,265		0	141,267	
Production Maintenance		514 IVC (305)	33.0%	31.07%	6,182		0	0.08%	75		0		0	6,257	
		514 SC1 (314)	34.0%		6,369		0		0		0		0	6,369	
		514 SC2 (315)	33.0%		6,182		0		0		0		0	6,182	
Transmission Maintenance		570			0		0	2.97%	2,771	0.02%	24		0	2,795	
Distribution Maintenance		598			0		0	5.62%	5,244	0.04%	48		0	5,292	
Administrative & General Maintenance		935			0		0		0	0.01%	12		0	12	
Total Payroll	Total Operation & Maintenance				60,292		0		93,303		119,222		0	272,817	272,817
Construction & Removal - Acct. 79300														0	
	Total Allocation													272,817	

Officer

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
TEP (based on Mass. Formula beginning 2005)	77.62%		73,623
Millennium (based on Mass. Formula beginning 2005)	5.44%		5,160
UNSG (based on Mass. Formula beginning 2005)	8.81%		8,356
UNSE (based on Mass. Formula beginning 2005)	8.13%		7,711
	100.0%	94,850.00	94,850
Operation & Maintenance (TEP Only)	100.0%	73,623	73,623
Construction & Removal	0.0%		0
	100.0%		73,623

Business Center

Operation & Maintenance Account Distribution		FERC Account (location)	*	Dist %	14.40% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	12.60% (003) Distribution	Dist %	73.00% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
		TEP			10,602		0		9,276		53,745		0	73,623	
		500 - GEN			10,602		0		0		0		0	10,602	
		580 - UDC			0		0		9,276		0		0	9,276	
		920 - SSU			0		0		0		53,745		0	53,745	
Total Payroll					10,602		0		9,276		53,745		0	73,623	73,623
	Total Allocation													73,623	

Account 21150-3306

Payroll Tax accrual required @ 10/31/05 for TEP PEP accrual	3,205,170	x	7.65%	=	245,196						
Preliminary Balance in A/C 21150 - 3306 (10/31/05)					(220,514)						
Under / (Over) Accrual					24,682						
			Unclassified		24,682	5,455	0	8,441	10,786	0	24,682
			Officer***		0	0	0	0	0	0	0
											24,682

FICA	7.65%	6.2% SS plus 1.45% Medicare
FUTA / SUTA	0.00%	Zero since not an incremental cost
WC	0.00%	Zero since not an incremental cost
	7.65%	

* Determined based on P/R by Function Report-Detail by Location for 2004
**See January 2005 journal for detailed back up of business center/distribution percentages
***Per L. Joyce stopped accruing Payroll Taxes on Officer portion in May-05

4.

UNSE(0783)11676

Tucson Electric Power Company
Unclassified Employees Incentive Compensation
J28
November-05

2-05 Per Michael Daranyi begin 2005 accruing @ 100%. This year we will break out officer from unclassified - change to expenditure type from 086 to 050 (UNC) and 052 (EXE). Business Center 006 (Other TEP) will not be allocated to.

8-2-05 Per discussion with Michael Daranyi, continue accruing PEP for July at 100%

10-05-05 Per e-mail from Michael Daranyi, adjust account for Annual total (both officers & Uncl) to $ 4,412,000.

Account 24000-3600	Summary	
Balance Required for 2005 PEP Accrual @ 11/30/05	4,044,337	(367,667) * 11
Mkt Dept. PEP - Paid in April	(7,040)	
Mkt Dept. PEP - Paid in July	(21,039)	
Officer PEP (T. Delawder) - Paid in April	(13,875)	
IS Admin - AG PEP - Paid in Sept	(7,500)	
Account 24000-3600 11/30/05 Balance - Preliminary	(3,627,213)	
Under / (Over) Accrual	367,870	

$287,500TEP Unclass + $66,584 TEP Exec + $13,583 UES Exec

Unclassified

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
UNSG	50.0%		0
UNSE	50.0%		0
	100.0%		0
Operation & Maintenance	100.0%	287,500	287,500
Construction & Removal	0.0%		0
	100.0%		287,500

Business Center

Operation & Maintenance Account Distribution		FERC Account (location)	Loc Dist *	Dist %	22.10% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	34.20% (003) Distribution	Dist %	43.70% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
					63,538		0		98,325		125,638		0	287,501	
Production		506 IV (300)	73.0%	42.25%	19,594		0	17.29%	17,000	0.54%	678		0	37,272	
		506 SC1 (314)	15.0%		4,027		0		0		0		0	4,027	
		506 SC2 (315)	12.0%		3,221		0		0		0		0	3,221	
Transmission		566			0		0	17.16%	16,873		0		0	16,873	
Distribution		588			0		0	23.81%	23,411	1.27%	1,596		0	25,007	
Customer Accounting & Service		903						7.52%	7,394	8.87%	8,386		0		
								7.42%	7,296	0.64%	804		0		
		903			0		0	14.94%	14,690	7.31%	9,184		0	23,874	Combine 903
Administrative & General		920		26.68%	16,952		0	18.13%	17,826	90.81%	114,092		0	148,870	
Production Maintenance		514 IVC (305)	33.0%	31.07%	6,515		0	0.08%	79		0		0	6,594	
		514 SC1 (314)	34.0%		6,712		0		0		0		0	6,712	
		514 SC2 (315)	33.0%		6,515		0		0		0		0	6,515	
Transmission Maintenance		570			0		0	2.97%	2,920	0.02%	25		0	2,945	
Distribution Maintenance		598			0		0	5.62%	5,526	0.04%	50		0	5,576	
Administrative & General Maintenance		935			0		0		0	0.01%	13		0	13	
Total Payroll	Total Operation & Maintenance				63,536		0		98,325		125,638		0	287,499	287,499
Construction & Removal - Acct. 79300														0	
	Total Allocation													287,499	

Officer

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
TEP (based on Mass. Formula beginning 2005)	77.62%		62,226
Millennium (based on Mass. Formula beginning 2005)	5.44%		4,361
UNSG (based on Mass. Formula beginning 2005)	8.81%		7,063
UNSE (based on Mass. Formula beginning 2005)	8.13%		6,518
	100.0%	80,167.00	80,168
Operation & Maintenance (TEP Only)	100.0%	62,226	62,226
Construction & Removal	0.0%		0
	100.0%		62,226

Business Center

Operation & Maintenance Account Distribution		FERC Account (location)	*	Dist %	14.40% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	12.60% (003) Distribution	Dist %	73.00% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
		TEP			8,961		0		7,840		45,425		0	62,226	
		500 - GEN			8,961		0		0		0		0	8,961	
		580 - UDC			0		0		7,840		0		0	7,840	
		920 - SSU			0		0		0		45,425		0	45,425	
Total Payroll					8,961		0		7,840		45,425		0	62,226	62,226
	Total Allocation													62,226	

Account 21150-3306

Payroll Tax accrual required @ 11/30/05 for TEP PEP accrual	3,477,984	x	7.65%	=	266,066					
Preliminary Balance in A/C 21150 - 3306 (11/30/05)					(237,241)					
Under / (Over) Accrual					28,825					
			Unclassified		28,825	6,370	0	9,858	12,597	0	28,825
			Officer***		0	0	0	0	0	0	0
											28,825

FICA	7.65%	6.2% SS plus 1.45% Medicare
FUTA / SUTA	0.00%	Zero since not an incremental cost
WC	0.00%	Zero since not an incremental cost
	7.65%	

* Determined based on P/R by Function Report-Detail by Location for 2004
**See January 2005 journal for detailed back up of business center/distribution percentages
***Per L. Joyce stopped accruing Payroll Taxes on Officer portion in May-05

UNSE(0783)11677

5.

Tucson Electric Power Company
Unclassified Employees Incentive Compensation
J28
December-05

2-05 Per Michael Daranyi begin 2005 accruing @ 100%. This year we will break out officer from unclassified - change to expenditure type from 086 to 050 (UNC) and 052 (EXE). Business Center 006 (Other TEP) will not be allocated to.

8-2-05 Per discussion with Michael Daranyi, continue accruing PEP for July at 100%

10-05-05 Per e-mail from Michael Daranyi, adjust account for Annual total (both officers & Uncl) to $ 4,412,000.

Account 24000-3600	Summary	
Balance Required for 2005 PEP Accrual @ 12/31/05	4,412,000	(367,667) * 12
Mkt Dept. PEP - Paid in April	(7,040)	
Mkt Dept. PEP - Paid in July	(21,039)	
Officer PEP (T. Delawder) - Paid in April	(13,875)	
IS Admin - AG PEP - Paid in Sept	(7,500)	
Account 24000-3600 12/31/05 Balance - Preliminary	(3,994,880)	
Under / (Over) Accrual	367,666	

$287,500TEP Unclass + $66,584 TEP Exec + $13,583 UES Exec

Unclassified

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
UNSG	50.0%		0
UNSE	50.0%		0
	100.0%		0
Operation & Maintenance	100.0%	287,499	287,499
Construction & Removal	0.0%		0
	100.0%		287,499

Business Center

Operation & Maintenance Account Distribution		FERC Account (location)	* Loc Dist	Dist %	22.10% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	34.20% (003) Distribution	Dist %	43.70% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
					63,537		0		98,325		125,637		0	287,499	
Production		506 IV (300)	73.0%	42.25%	19,584		0	17.29%	17,000	0.54%	678		0	37,272	
		506 SC1 (314)	15.0%		4,027		0		0		0		0	4,027	
		506 SC2 (315)	12.0%		3,221		0		0		0		0	3,221	
Transmission		566			0		0	17.16%	16,873		0		0	16,873	
Distribution		588			0		0	23.81%	23,411	1.27%	1,596		0	25,007	
Customer Accounting & Service		903						7.52%	7,394	6.67%	8,380		0		
								7.42%	7,296	0.64%	804		0		
		903			0		0	14.94%	14,690	7.31%	9,184		0	23,874	Combine 903
Administrative & General		920		26.68%	16,952		0	18.13%	17,826	90.81%	114,091		0	148,869	
Production Maintenance		514 IVC (305)	33.0%	31.07%	6,515		0	0.08%	79		0		0	6,594	
		514 SC1 (314)	34.0%		6,712		0		0		0		0	6,712	
		514 SC2 (315)	33.0%		6,515		0		0		0		0	6,515	
Transmission Maintenance		570			0		0	2.97%	2,920	0.02%	25		0	2,945	
Distribution Maintenance		598			0		0	5.62%	5,526	0.04%	50		0	5,576	
Administrative & General Maintenance		935			0		0		0	0.01%	13		0	13	
Total Payroll	Total Operation & Maintenance				63,536		0		98,325		125,637		0	287,498	287,498
Construction & Removal - Acct. 79300														0	
	Total Allocation													287,498	

Officer

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
TEP (based on Mass. Formula beginning 2005)	77.62%		62,226
Millennium (based on Mass. Formula beginning 2005)	5.44%		4,361
UNSG (based on Mass. Formula beginning 2005)	8.81%		7,063
UNSE (based on Mass. Formula beginning 2005)	8.13%		6,518
	100.0%	80,167.00	80,168
Operation & Maintenance (TEP Only)	100.0%	62,226	62,226
Construction & Removal	0.0%		0
	100.0%		62,226

Business Center

Operation & Maintenance Account Distribution		FERC Account (location)	*	Dist %	14.40% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	12.60% (003) Distribution	Dist %	73.00% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
		TEP			8,961		0		7,840		45,425		0	62,226	
		500 - GEN			8,961		0		0		0		0	8,961	
		580 - UDC			0		0		7,840		0		0	7,840	
		920 - SSU			0		0		0		45,425		0	45,425	
Total Payroll					8,961		0		7,840		45,425		0	62,226	62,226
	Total Allocation													62,226	

Account 21150-3306

Payroll Tax accrual required @ 12/31/05 for TEP PEP accrual	3,794,853	x	7.65%	=	290,306					
Preliminary Balance in A/C 21150 - 3306 (12/31/05)					(264,753)					
Under / (Over) Accrual					25,553					
			Unclassified		25,553	5,647	0	8,739	11,167	0	25,553
			Officer***		0	0	0	0	0	0	0
											25,553

FICA	7.65%	6.2% SS plus 1.45% Medicare
FUTA / SUTA	0.00%	Zero since not an incremental cost
WC	0.00%	Zero since not an incremental cost
	7.65%	

* Determined based on P/R by Function Report-Detail by Location for 2004
**See January 2005 journal for detailed back up of business center/distribution percentages
***Per L. Joyce stopped accruing Payroll Taxes on Officer portion in May-05

UNSE(0783)11678

Final 2005 PEP Adjustment by Company

TEP Unclassified (Exp Type 050)

PEP Accrual Recorded thru Monthly J28	$ 3,463,421	
Less: 2004 True-up Recorded in March	(358,553)	
Less: Adjustment Recorded on Dec J959	(1,150,004)	
Total Preliminary Expense Recorded	1,954,864	
Final Award Authorized	2,000,000	
Adjustment Required	$ 45,136	As the final true-up is immaterial it is all being adjusted to FERC 920 and SSU

Officer PEP (Exp Type 052)

	TEP	MEH	UNSG	UNSE	
Accrual Recorded thru Monthly J28 by Company	1,058,676	60,319	97,689	90,148	
Less: Adjustment Recorded on Dec J959	(248,898)	(17,444)	(28,250)	(26,070)	
Total Preliminary Expense Recorded by Company	809,778	42,875	69,439	64,078	986,170
Final Award Authorized**	465,720	32,640	52,860	48,780	600,000
Adjustment Required	(344,058)	(10,235)	(16,579)	(15,298)	(386,170)

a.

**Allocated based on Mass formula

TEP Payroll Tax Adjustment

Unclassified Accrual Required	2,000,000	0.0765	153,000
Officer Accrual Required	600,000	0.00145	870
			153,870
Preliminary Accrual Recorded			202,331
Adjustment Required			(48,461)

UNSG PEP Adjustment

	PEP	
Total Preliminary Expense Recorded	162,667	
Final Award Authorized	140,000	
Adjustment Required	(22,667)	See attached for allocation by FERC and Bus Center

UNSG Payroll Tax Adjustment

Accrual Required	140,000	0.0765	10,710
Preliminary Accrual Recorded			12,444
Adjustment Required			(1,734)

UNSE PEP Adjustment

	PEP	
Total Preliminary Expense Recorded	70,667	
Final Award Authorized	60,000	
Adjustment Required	(10,667)	See attached for allocation by FERC and Bus Center

UNSE Payroll Tax Adjustment

Accrual Required	60,000	0.0765	4,590
Preliminary Accrual Recorded			5,406
Adjustment Required			(816)

7.

UNSE(0783)11679

Tucson Electric Power Company
Unclassified Employees Incentive Compensation
J28
December-05

2-05 Per Michael Daranyi begin 2005 accruing @ 100% This year we will break out officer from unclassified - change to expenditure type from 086 to 050 (UNC) and 052 (EXE). Business Center 006 (Other TEP) will not be allocated to.

8-2-05 Per discussion with Michael Daranyi, continue accruing PEP for July at 100%

10-05-05 Per e-mail from Michael Daranyi, adjust account for Annual total (both officers & Uncl) to $ 4,412,000.

Account 24000-3600

	Summary	
Balance Required for 2005 PEP Accrual @ 12/31/05	4,412,000	(367,667) * 12
Mkt Dept. PEP - Paid in April	(7,040)	
Mkt Dept. PEP - Paid in July	(21,039)	
Officer PEP (T. Delawder) - Paid in April	(13,875)	
IS Admin - AG PEP - Paid in Sept	(7,500)	
Account 24000-3600 12/31/05 Balance - Preliminary	(4,362,546)	
50% Adjustment to account	(1,470,666)	
Under / (Over) Accrual	(1,470,666)	

100% to plan	50% to Plan
5,882,667 /2	2,941,334
	4,412,000
	(1,470,666)

$287,500TEP Unclass + $66,584 TEP Exec + $13,583 UES Exec

Unclassified

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
UNSG	50.0%		0
UNSE	50.0%		0
	100.0%		0
Operation & Maintenance	100.0%	(1,150,000)	(1,150,000)
Construction & Removal	0.0%		0
	100.0%		(1,150,000)

Business Center

Operation & Maintenance Account Distribution	FERC Account (location)	Loc Dist	Dist %	22.10% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	34.20% (003) Distribution	Dist %	43.70% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
				(254,150)		0		(393,300)		(502,550)		0	(1,150,000)	
Production	506 IV (300)	73.0%	42.25%	(78,391)		0	17.29%	(68,002)	0.54%	(2,714)		0	(149,107)	
	506 SC1 (314)	15.0%		(16,107)		0		0		0		0	(16,107)	
	506 SC2 (315)	12.0%		(12,885)		0		0		0		0	(12,885)	
Transmission	566			0		0	17.16%	(67,490)		0		0	(67,490)	
Distribution	588			0		0	23.81%	(93,645)	1.27%	(6,382)		0	(100,027)	
Customer Accounting & Service	903						7.52%	(29,576)	6.87%	(33,620)		0		
							7.42%	(29,183)	0.64%	(3,218)		0		
	903			0		0	14.94%	(58,759)	7.31%	(36,736)		0	(95,495)	Combine 903
Administrative & General	920		26.68%	(67,807)		0	18.13%	(71,305)	90.81%	(456,366)		0	(595,478)	
Production Maintenance	514 IVC (305)	33.0%	31.07%	(26,058)		0	0.08%	(315)		0		0	(26,373)	
	514 SC1 (314)	34.0%		(26,848)		0		0		0		0	(26,848)	
	514 SC2 (315)	33.0%		(26,058)		0		0		0		0	(26,058)	
Transmission Maintenance	570			0		0	2.97%	(11,681)	0.02%	(101)		0	(11,782)	
Distribution Maintenance	598			0		0	5.62%	(22,103)	0.04%	(201)		0	(22,304)	
Administrative & General Maintenance	935			0		0		0	0.01%	(50)		0	(50)	
Total Payroll — Total Operation & Maintenance				(254,154)		0		(393,300)		(502,550)		0	(1,150,004)	(1,150,004)
Construction & Removal - Acct. 79300													0	
Total Allocation													(1,150,004)	

Officer

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
TEP (based on Mass. Formula beginning 2005)	77.62%		(248,889)
Millennium (based on Mass. Formula beginning 2005)	5.44%		(17,444)
UNSG (based on Mass. Formula beginning 2005)	8.81%		(28,250)
UNSE (based on Mass. Formula beginning 2005)	8.13%		(26,070)
	100.0%	(320,664.00)	(320,663)
Operation & Maintenance (TEP Only)	100.0%	(248,899)	(248,899)
Construction & Removal	0.0%		0
	100.0%		(248,899)

Business Center

Operation & Maintenance Account Distribution	FERC Account (location)	Dist %	14.40% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	12.60% (003) Distribution	Dist %	73.00% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
	TEP		(35,841)		0		(31,361)		(181,696)		0	(248,898)	
	500 - GEN		(35,841)		0		0		0		0	(35,841)	
	580 - UDC		0		0		(31,361)		0		0	(31,361)	
	920 - SSU		0		0		0		(181,696)		0	(181,696)	
Total Payroll			(35,841)		0		(31,361)		(181,696)		0	(248,898)	(248,898)
Total Allocation												(248,898)	

Account 21150-3306

Payroll Tax accrual required @ 12/31/05 for TEP PEP accrual	2,644,853	x	7.65%	=	202,331
Preliminary Balance in A/C 21150 - 3306 (12/31/05)					(290,306)
Under / (Over) Accrual					(87,975)
			Unclassified		(87,975)
			Officer***		0

(87,975)	(19,443)	0	(30,087)	(38,445)	0	(87,975)
0	0	0	0	0	0	0
						(87,975)

FICA	7.65%	6.2% SS plus 1.45% Medicare
FUTA / SUTA	0.00%	Zero since not an incremental cost
WC	0.00%	Zero since not an incremental cost
	7.65%	

* Determined based on P/R by Function Report-Detail by Location for 2004
**See January 2005 journal for detailed back up of business center/distribution percentages
***Per L. Joyce stopped accruing Payroll Taxes on Officer portion in May-05

UNSE(0783)11680

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8/22/2007

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Tucson Electric Power Company
Unclassified Employees Incentive Compensation
J28
January-06

Account 24000-3600	Summary
Balance Required for 2005 PEP Accrual @ 12/31/05 to be pd 03/06	2,550,846
Balance Required for 2006 PEP Accrual @ 01/31/06	1,116,666
Mkt Dept. PEP - Paid in Jan for "Guarsnteed Home"	(14,324)
Account 24000-3600 01/31/06 Balance - Preliminary	(2,536,522)
Under / (Over) Accrual	1,116,666

2-06 Per Michael Daranyi begin 2006 accruing @ 100%. TEP employee's @ $5.1 million & Officers at 100% of $1.6 million

Jan 06 ("$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) = 558,333
558,333

Unclassified

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
UNSG	50.0%		0
UNSE	50.0%		0
	100.0%		0
Operation & Maintenance	100.0%	425,000	425,000
Construction & Removal	0.0%		0
	100.0%		425,000

Operation & Maintenance Account Distribution

Business Center

		FERC Account (location)	* Loc Dist	Dist %	21.57% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	31.37% (003) Distribution	Dist %	47.06% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
					91,673		0		133,323		200,005		0	425,001	
Production		506 IV (300)	72.3%	39.11%	25,927		0	17.93%	23,906	0.30%	600		0	50,432	
		506 SC1 (314)	14.6%		5,235		0		0		0		0	5,235	
		506 SC2 (315)	13.1%		4,697		0		0		0		0	4,697	
Transmission		566			0		0	15.41%	20,545		0		0	20,545	
Distribution		588			0		0	26.48%	35,304	2.25%	4,500		0	39,804	
Customer Accounting & Service		903						5.86%	7,813	5.42%	10,840		0		
								6.18%	8,235	0.63%	1,680		0		
		903			0		0	12.04%	16,052	6.25%	12,500		0	28,552	Combine 903
Administrative & General		920		28.14%	25,797		0	18.53%	24,705	91.05%	182,105		0	232,607	
Production Maintenance		514 IVC (305)	36.0%	32.75%	10,808		0	0.05%	67		0		0	10,875	
		514 SC1 (314)	31.7%		9,517		0		0		0		0	9,517	
		514 SC2 (315)	32.3%		9,697		0		0		0		0	9,697	
Transmission Maintenance		570			0		0	3.72%	4,960	0.00%	0		0	4,960	
Distribution Maintenance		598			0		0	5.85%	7,799	0.06%	120		0	7,919	
Administrative & General Maintenance		935			0		0		0	0.08%	160		0	160	
Total Payroll	Total Operation & Maintenance				91,678		0		133,337		199,985		0	425,000	425,000
Construction & Removal - Acct. 79300														0	
	Total Allocation													425,000	

Officer

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
TEP (based on Mass. Formula beginning 2005)	78.86%		105,146
Millennium (based on Mass. Formula beginning 2005)	2.86%		3,813
UNSG (based on Mass. Formula beginning 2005)	9.42%		12,560
UNSE (based on Mass. Formula beginning 2005)	8.86%		11,813 a
	100.0%	133,333.00	133,332
Operation & Maintenance (TEP Only)	100.0%	105,146	105,146
Construction & Removal	0.0%		0
	100.0%		105,146

Operation & Maintenance Account Distribution

Business Center

		FERC Account (location)	*	Dist %	8.74% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	10.11% (003) Distribution	Dist %	81.15% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
		TEP			9,190		0		10,630		85,326		0	105,146	
		500 - GEN			9,190		0		0		0		0	9,190	
		580 - UDC			0		0		10,630		0		0	10,630	
		920 - SSU			0		0		0		85,326		0	85,326	
Total Payroll					9,190		0		10,630		85,326		0	105,146	105,146
	Total Allocation													105,146	

Account 21150-3306

Payroll Tax accrual required @ 12/31/05 for 2005 TEP PEP accrual	2,000,000	x	7.65%	=	153,000						
Payroll Tax accrual required @ 01/31/06 for 2006 TEP PEP accrual	425,000	x	7.65%	=	32,513						
Preliminary Balance in A/C 21150 - 3306 (01/31/06)					(152,508)						
Under / (Over) Accrual					33,005						
			Unclassified		33,005	7,120	0	10,355	15,530	0	33,005
			Officer***		0	0	0	0	0	0	0
											33,005

FICA	7.65%	6.2% SS plus 1.45% Medicare
FUTA / SUTA	0.00%	Zero since not an incremental cost
WC	0.00%	Zero since not an incremental cost
	7.65%	

* Determined based on P/R by Function Report-Detail by Location for 2004
**See January 2005 journal for detailed back up of business center/distribution percentages
***Per L. Joyce stopped accruing Payroll Taxes on Officer portion in May-05

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UNSE(0783)11681

Tucson Electric Power Company
Unclassified Employees Incentive Compensation
J28
~~January 06~~ Feb-06

2-06 Per Michael Darenyi begin 2006 accrung @ 100% TEP employee's @ $5.1 million & Officers at 100% of $1 6 million
3-06 Per Michael Darani - Keep it the same for Feb 2006

Account 24000-3600

	Summary
Balance Required for 2005 PEP Accrual @ 12/31/05 to be pd 03/06	2,550,846
Balance Required for 2006 PEP Accrual @ 02/28/06	1,116,666 *
Mkt Dept. PEP - Paid in Jan for "Guaranteed Home"	(14,324)
Adjusting Entry needed to move Bentley Erdwurm sign on bonus	(10,000) J904 done in Feb
Account 24000-3600 02/28/06 Balance - Preliminary	(3,084,854)
Under / (Over) Accrual	558,334

Jan 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
Feb 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
	1,116,666

Unclassified

Operation & Maintenance / Capital Distribution

	Percent	Required Accrual	Allocation
UNSG	50.0%		0
UNSE	50.0%		0
	100.0%		0
Operation & Maintenance	100.0%	425,000	425,000
Construction & Removal	0.0%		0
	100.0%		425,000

Operation & Maintenance Account Distribution

Business Center

	FERC Account (location)	* Loc Dist	Dist %	21.57% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	31.37% (003) Distribution	Dist %	47.06% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
Production				91,673		0		133,323		200,005		0	425,001	
	506 IV (300)	72.3%	39.11%	25,927		0	17.93%	23,905	0.30%	600		0	50,432	
	506 SC1 (314)	14.6%		5,235		0		0		0		0	5,235	
	506 SC2 (315)	13.1%		4,697		0		0		0		0	4,697	
Transmission	566			0		0	15.41%	20,545		0		0	20,545	
Distribution	588			0		0	26.48%	35,304	2.25%	4,500		0	39,804	
Customer Accounting & Service	903						5.85%	7,813	5.42%	10,840		0		
							8.16%	8,230	0.69%	1,380		0		
	903			0		0	12.04%	16,052	6.25%	12,500		0	28,552	Combine 903
Administrative & General	920		28.14%	25,797		0	18.53%	24,705	91.05%	182,105		0	232,607	
Production Maintenance	514 IVC (305)	36.0%	32.75%	10,808		0	0.05%	67		0		0	10,875	
	514 SC1 (314)	31.7%		9,517		0		0		0		0	9,517	
	514 SC2 (315)	32.3%		9,697		0		0		0		0	9,697	
Transmission Maintenance	570			0		0	3.72%	4,960	0.00%	0		0	4,960	
Distribution Maintenance	596			0		0	5.85%	7,799	0.06%	120		0	7,919	
Administrative & General Maintenance	935			0		0		0	0.08%	160		0	160	
Total Payroll	Total Operation & Maintenance			91,678		0		133,337		199,985		0	425,000	425,000
Construction & Removal - Acct. 79300													0	
Total Allocation													425,000	

Officer

Operation & Maintenance / Capital Distribution

	Percent	Required Accrual	Allocation
TEP (based on Mass. Formula beginning 2005)	78.86%		105,146
Millennium (based on Mass. Formula beginning 2005)	2.86%		3,813
UNSG (based on Mass Formula beginning 2005)	9.42%		12,560
UNSE (based on Mass. Formula beginning 2005)	8.86%		11,814 a
	100.0%	133,333.00	133,333
Operation & Maintenance (TEP Only)	100.0%	105,146	105,146
Construction & Removal	0.0%		0
	100.0%		105,146

Operation & Maintenance Account Distribution

Business Center

	FERC Account (location)	Dist %	8.74% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	10.11% (003) Distribution	Dist %	81.15% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
	TEP		9,190		0		10,630		85,326		0	105,146	
	500 - GEN		9,190		0		0		0		0	9,190	
	580 - UDC		0		0		10,630		0		0	10,630	
	920 - SSU		0		0		0		85,326		0	85,326	
Total Payroll			9,190		0		10,630		85,326		0	105,146	105,146
Total Allocation												105,146	

Account 21150-3306

Payroll Tax accrual required @ 12/31/05 for 2005 TEP PEP accrual	2,000,000	x	7.65%	=	153,000
Payroll Tax accrual required @ 02/28/06 for 2006 TEP PEP accrual	2 850,000	x	7.65%	=	65,025
Preliminary Balance in A/C 21150 - 3306 (02/28/06)					(185,265)
Under / (Over) Accrual					32,760

Unclassified	32,760	7,067	0	10,278	15,415	0	32,760
Officer***	0	0	0	0	0	0	0
							32,760

FICA	7.65%	6 2% SS plus 1 45% Medicare
FUTA / SUTA	0 00%	Zero since not an incremental cost
WC	0 00%	Zero since not an incremental cost
	7.65%	

* Determined based on P/R by Function Report-Detail by Location for 2004
**See January 2006 journal for detailed back up of business center/distribution percentages
***Per L Joyce stopped accruing Payroll Taxes on Officer portion in May-05

Jan 06 ('$425,000 TEP Unclass) =	425,000
Feb 06 ('$425,000 TEP Unclass) =	425,000
	850,000.00

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8/22/2007

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Tucson Electric Power Company
Unclassified Employees Incentive Compensation
J28
January-06 — mae - gu

Account 24000-3600

	Summary
Balance Required for 2005 PEP Accrual @ 12/31/05 to be pd 03/06	2,550,846
Balance Required for 2006 PEP Accrual @ 02/28/06	1,116,666 [1]
Mkt Dept PEP - Paid in Jan for "Guaranteed Home"	(14,324)
Adjusting Entry needed to move Bentley Erdwurm sign on bonus	(10,000) J904 done in Feb
Account 24000-3600 02/28/06 Balance - Preliminary	(3,084,854)
Under / (Over) Accrual	558,334

2-06 Per Michael Daranyi begin 2006 accruing @ 100% TEP employee's @ $5.1 million & Officers at 100% of $1.6 million
3-06 Per Michael Darani - Keep it the same for Feb 2006

Jan 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
Feb 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
	1,116,666

Unclassified

Operation & Maintenance / Capital Distribution

	Percent	Required Accrual	Allocation
UNSG	50.0%		0
UNSE	50.0%		0
	100.0%		0
Operation & Maintenance	100.0%	425,000	425,000
Construction & Removal	0.0%		0
	100.0%		425,000

Operation & Maintenance Account Distribution

Business Center

	FERC Account (location)	* Loc Dist	Dist %	21.57% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	31.37% (003) Distribution	Dist %	47.06% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
Production				91,673		0		133,323		200,005		0	425,001	
	506 IV (300)	72.3%	39.11%	25,927		0	17.93%	23,905	0.30%	600		0	50,432	
	506 SC1 (314)	14.6%		5,235		0		0		0		0	5,235	
	506 SC2 (315)	13.1%		4,697		0		0		0		0	4,697	
Transmission	586			0		0	15.41%	20,545		0		0	20,545	
Distribution	588			0		0	26.46%	35,304	2.25%	4,500		0	39,804	
Customer Accounting & Service	903						5.80%	7,813	5.42%	10,840		0		
							6.18%	8,248	0.83%	1,660		0		
	903			0		0	12.04%	16,052	6.25%	12,500		0	28,552	Combine 903
Administrative & General	920		28.14%	25,797		0	18.53%	24,705	91.05%	182,105		0	232,607	
Production Maintenance	514 IVC (305)	36.0%	32.75%	10,808		0	0.05%	67		0		0	10,875	
	514 SC1 (314)	31.7%		9,517		0		0		0		0	9,517	
	514 SC2 (315)	32.3%		9,697		0		0		0		0	9,697	
Transmission Maintenance	570			0		0	3.72%	4,960	0.00%	0		0	4,960	
Distribution Maintenance	596			0		0	5.85%	7,799	0.06%	120		0	7,919	
Administrative & General Maintenance	935			0		0		0	0.08%	160		0	160	
Total Payroll	Total Operation & Maintenance			91,678		0		133,337		199,985		0	425,000	425,000
Construction & Removal - Acct. 79300													0	
Total Allocation													425,000	

Officer

Operation & Maintenance / Capital Distribution

	Percent	Required Accrual	Allocation
TEP (based on Mass. Formula beginning 2005)	78.88%		105,146
Millennium (based on Mass. Formula beginning 2005)	2.86%		3,813
UNSG (based on Mass. Formula beginning 2005)	9.42%		12,560
UNSE (based on Mass. Formula beginning 2005)	8.86%		11,814 a
	100.0%	133,333.00	133,333
Operation & Maintenance (TEP Only)	100.0%	105,146	105,146
Construction & Removal	0.0%		0
	100.0%		105,146

Operation & Maintenance Account Distribution

Business Center

	FERC Account (location)	* Dist %	8.74% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	10.11% (003) Distribution	Dist %	81.15% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
	TEP		9,190		0		10,630		85,326		0	105,146	
	500 - GEN		9,190		0		0		0		0	9,190	
	580 - UDC		0		0		10,630		0		0	10,630	
	920 - SSU		0		0		0		85,326		0	85,326	
Total Payroll			9,190		0		10,630		85,326		0	105,146	105,146
Total Allocation												105,146	

Account 21150-3306

Payroll Tax accrual required @ 12/31/05 for 2005 TEP PEP accrual	2,000,000	x	7.65%	=	153,000
Payroll Tax accrual required @ 02/28/06 for 2006 TEP PEP accrual [2]	850,000	x	7.65%	=	65,025
Preliminary Balance in A/C 21150 - 3306 (02/28/06)					(185,265)
Under / (Over) Accrual					32,760

Unclassified	32,760	7,067	0	10,278	15,415	0	32,760
Officer***	0	0	0	0	0	0	0
							32,760

FICA	7.65%	6.2% SS plus 1.45% Medicare
FUTA / SUTA	0.00%	Zero since not an incremental cost
WC	0.00%	Zero since not an incremental cost
	7.65%	

* Determined based on P/R by Function Report-Detail by Location for 2004
**See January 2006 journal for detailed back up of business center/distribution percentages
***Per L. Joyce stopped accruing Payroll Taxes on Officer portion in May-05

[1] Jan 06 ('$425,000 TEP Unclass) =	425,000
Feb 06 ('$425,000 TEP Unclass) =	425,000
	850,000.00

UNSE(0783)11683

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Tucson Electric Power Company
Unclassified Employee Incentive Compensation
J28
April-06

Account 24000-3800	Summary
Balance Required for 2006 PEP Accrual @ 04/30/06	2,233,332 [1]
Mkt Dept PEP - Paid in Jan for "Guaranteed Home"	(14,324)
Mkt Dept. PEP - Paid in Apr for "Guaranteed Home"	(3,318)
Account 24000-3800 03/31/06 Balance - Preliminary	(1,657,357)
Under / (Over) Accrual	558,333

1-06 Per Michael Daranyi begin 2006 accruing @ 100% TEP employee's @ $5 1 million & Officers at 100% of $1 6 million
2-06 Per Michael Darani - Keep it the same for Feb 2006
3-06 Per Michael Darani - Keep it the same for March 2006 2005 PEP was paid out at $2,278,560 while $2,550,560 was accrued Of the $2,278,560, 600,000 was paid out to officers leaving $1,678,560 pay-out to O&M
4-06 Per Michael Darani - Keep it the same for Apr 2006 **REQUEST TO MOVE TAX PORTION TO EXPENDITURE TYPE 070 - CAME 04/07/06 - INCLUDE THIS CHANGE ON THE APRIL ENTRY**

Jan 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
Feb 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
Mar 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
Apr 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
	2,233,332

Unclassified

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
UNSG	50.0%		0
UNSE	50.0%		0
	100.0%		0
Operation & Maintenance	100.0%	425,000	425,000
Construction & Removal	0.0%		0
	100.0%		425,000

Operation & Maintenance Account Distribution

	FERC Account (location)	* Loc Dist	Dist %	21.57% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	31.37% (003) Distribution	Dist %	47.06% (004) Corporate	Dist %	0.00% (005) Other	Total	Total Expense By Bus Ctr
				Business Center										
Production				91,673		0		133,323		200,005		0	425,001	
	506 IV (300)	72 3%	39.11%	25,927		0	17.93%	23,905	0.30%	600		0	50,432	
	506 SC1 (314)	14.6%		5,235		0		0		0		0	5,235	
	506 SC2 (315)	13 1%		4,697		0		0		0		0	4,697	
Transmission	566			0		0	15.41%	20,545		0		0	20,545	
Distribution	588			0		0	26 48%	35,304	2.25%	4,500		0	39,804	
Customer Accounting & Service	903						5.86%	7,813	5.42%	10,840		0		
							6.18%	8,236	0.83%	1,660		0		
	903			0		0	12.04%	16,052	6.25%	12,500		0	28,552	Combine 903
Administrative & General	920		28.14%	25,797		0	18.53%	24,705	91.05%	182,105		0	232,607	
Production Maintenance	514 IVC (305)	36 0%	32.75%	10,808		0	0.05%	67		0		0	10,875	
	514 SC1 (314)	31 7%		9,517		0		0		0		0	9,517	
	514 SC2 (315)	32 3%		9,697		0		0		0		0	9,697	
Transmission Maintenance	570			0		0	3 72%	4,960	0.00%	0		0	4,960	
Distribution Maintenance	598			0		0	5.85%	7,799	0.06%	120		0	7,919	
Administrative & General Maintenance	935			0		0		0	0.08%	160		0	160	
Total Payroll	Total Operation & Maintenance			91,678		0		133,337		199,985		0	425,000	425,000
Construction & Removal - Acct. 79300													0	
	Total Allocation												425,000	

Officer

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
TEP (based on Mass. Formula beginning 2005)	78.86%		105,146
Millennium (based on Mass. Formula beginning 2005)	2.86%		3,813
UNSG (based on Mass. Formula beginning 2005)	9.42%		12,560
UNSE (based on Mass. Formula beginning 2005)	8.86%		11,814 a
	100.0%	133,333.00	133,333
Operation & Maintenance (TEP Only)	100.0%	105,146	105,146
Construction & Removal	0.0%		0
	100.0%		105,146

Operation & Maintenance Account Distribution

	FERC Account (location)	Dist %	8.74% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	10.11% (003) Distribution	Dist %	81.15% (004) Corporate	Dist %	0.00% (005) Other	Total	Total Expense By Bus Ctr
			Business Center										
	TEP		9,190		0		10,630		85,326		0	105,146	
	500 - GEN		9,190		0		0		0		0	9,190	
	580 - UDC		0		0		10,630		0		0	10,630	
	920 - SSU		0		0		0		85,326		0	85,326	
Total Payroll			9,190		0		10,630		85,326		0	105,146	105,146
	Total Allocation											105,146	

Account 21150-3306

Payroll Tax accrual required @ 04/30/06 for 2006 TEP PEP accrual	[2]	1,700,000	x	7.65%	=	130,050							
Preliminary Balance in A/C 21150 - 3306 (03/31/06)						(94,159)							
Under / (Over) Accrual						35,891							
				Unclassified		35,891	7,742	0	11,260	16,889	0	35,891	
				Officer***		0	0	0	0	0	0	0	
												35,891	

FICA	7.65%	6 2% SS plus 1 45% Medicare
FUTA / SUTA	0 00%	Zero since not an incremental cost
WC	0 00%	Zero since not an incremental cost
	7.65%	

* Determined based on P/R by Function Report-Detail by Location for 2004
**See January 2006 journal for detailed back up of business center/distribution percentages
***Per L. Joyce stopped accruing Payroll Taxes on Officer portion in May-05

Jan 06 ('$425,000 TEP Unclass) =	425,000
Feb 06 ('$425,000 TEP Unclass) =	425,000
Mar 06 ('$425,000 TEP Unclass) =	425,000
Apr 06 ('$425,000 TEP Unclass) =	425,000
	1,700,000

I/C Statement Impact

TEP	586,037 00
UNSE	11,814 00
UNSG	12,560 00
MEH	3,813 00
ck figure	594,224.00

UNSE(0783)11684

12

8/22/2007

C:\Documents and Settings\sus02861 UNISOURCE 000\Local Settings\Temporary Internet Files\OLK3E\PEP Accrual 042006

Tucson Electric Power Company
Unclassified Employees Incentive Compensation
J28
~~June 06~~ May 06

Account 24000-3600

	Summary
Balance Required for 2006 PEP Accrual @ 06/30/06	3,349,998 1
Mkt Dept PEP - Paid in Jan for "Guaranteed Home"	(14,324)
Mkt Dept PEP - Paid in Apr for "Guaranteed Home"	(3,318)
Account 24000-3600 05/31/06 Balance - Preliminary	(2,774,023)
Under / (Over) Accrual	558,333

1-06 Per Michael Darany! begin 2006 accruing @ 100% TEP employee's @ $5.1 million & Officers at 100% of $1.6 million
2-06 Per Michael Darani - Keep it the same for Feb 2006
3-06 Per Michael Darani - Keep it the same for March 2006 2005 PEP was paid out at $2,278,560 while $2,550,560 was accrued. Of the $2,278,560, 600,000 was paid out to officers leaving $1,678,560 pay-out to O&M
4-06 Per Michael Darani - Keep it the same for Apr 2006 -REQUEST TO MOVE TAX PORTION TO EXPENDITURE TYPE 070 - CAME 04/07/06 - INCLUDE THIS CHANGE ON THE APRIL ENTRY
05-06 Per Michael Darani - Keep it the same for May 2006
06-06 Per Michael Darani - Keep it the same for June 2006

Jan 06 ($425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
Feb 06 ($425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
Mar 06 ($425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
Apr 06 ($425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
May 06 ($425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
Jun 06 ($425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
	3,349,998 1

Unclassified

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
UNSG	50.0%		0
UNSE	50.0%		0
	100.0%		0
Operation & Maintenance	100.0%	425,000	425,000
Construction & Removal	0.0%		0
	100.0%		425,000

Operation & Maintenance Account Distribution

			* Loc Dist	Dist %	21.57% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	31.37% (003) Distribution	Dist %	47.06% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
					91,673		0		133,323		200,005		0	425,001	
Production		506 IV (300)	72.3%	39.11%	25,927		0	17.93%	23,905	0.30%	600		0	50,432	
		506 SC1 (314)	14.6%		5,235		0		0		0		0	5,236	
		506 SC2 (315)	13.1%		4,697		0		0		0		0	4,697	
Transmission		566			0		0	15.41%	20,545		0		0	20,545	
Distribution		588			0		0	26.48%	35,304	2.25%	4,500		0	39,804	
Customer Accounting & Service		903						8.86%	7,813	5.42%	10,840		0		
								6.16%	8,239	5.63%	1,680		0		
		903			0		0	12.04%	16,052	6.25%	12,500		0	28,552	Combine 903
Administrative & General		920		28.14%	25,797		0	18.53%	24,705	91.05%	182,105		0	232,607	
Production Maintenance		514 IVC (305)	36.0%	32.76%	10,608		0	0.05%	67		0		0	10,675	
		514 SC1 (314)	31.7%		9,517		0		0		0		0	9,517	
		514 SC2 (315)	32.3%		9,697		0		0		0		0	9,697	
Transmission Maintenance		570			0		0	3.72%	4,960	0.00%	0		0	4,960	
Distribution Maintenance		598			0		0	5.85%	7,799	0.06%	120		0	7,919	
Administrative & General Maintenance		935			0		0		0	0.08%	160		0	160	
Total Payroll	Total Operation & Maintenance				91,678		0		133,337		199,985		0	425,000	425,000
Construction & Removal - Acct. 79300														0	
	Total Allocation													425,000	

Officer

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
TEP (based on Mass. Formula beginning 2005)	78.86%		105,146
Millennium (based on Mass. Formula beginning 2005)	2.86%		3,813
UNSG (based on Mass. Formula beginning 2005)	9.42%		12,560
UNSE (based on Mass. Formula beginning 2005)	8.86%		11,814 a
	100.0%	133,333.00	133,333
Operation & Maintenance (TEP Only)	100.0%	105,146	105,146
Construction & Removal	0.0%		0
	100.0%		105,146

Operation & Maintenance Account Distribution

	FERC Account (location)	Dist %	8.74% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	10.11% (003) Distribution	Dist %	81.15% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
	TEP		9,190		0		10,630		85,326		0	105,146	
	500 - GEN		9,190		0		0		0		0	9,190	
	580 - UDC		0		0		10,630		0		0	10,630	
	920 - SSU		0		0		0		85,326		0	85,326	
Total Payroll			9,190		0		10,630		85,326		0	105,146	105,146
Total Allocation												105,146	

Account 21150-3306

Payroll Tax accrual required @ 06/30/06 for 2006 TEP PEP accrual	2	2,550,000	x	7.65%	=	195,075					
Preliminary Balance in A/C 21150 - 3306 (05/31/06)						(162,563)					
Under / (Over) Accrual						32,512					
				Unclassified		32,512	7,013	0	10,200	15,299	0 32,512
				Officer***		0	0	0	0	0	0 0
											32,512

FICA	7.65%	6.2% SS plus 1.45% Medicare
FUTA / SUTA	0.00%	Zero since not an incremental cost
WC	0.00%	Zero since not an incremental cost
	7.65%	

Jan 06 ($425,000 TEP Unclass) =	425,000
Feb 06 ($425,000 TEP Unclass) =	425,000
Mar 06 ($425,000 TEP Unclass) =	425,000
Apr 06 ($425,000 TEP Unclass) =	425,000
May 06 ($425,000 TEP Unclass) =	425,000
Jun 06 ($425,000 TEP Unclass) =	425,000
	2,550,000 2

I/C Statement Impact	
TEP	562,658 00
UNSE	11,814 00
UNSG	12,560 00
MEH	3,813 00
ck figure	590,845 00

* Determined based on P/R by Function Report-Detail by Location for 2004
**See January 2006 journal for detailed back up of business center/distribution percentages
***Per L. Joyce stopped accruing Payroll Taxes on Officer portion in May-05

UNSE(0783)11685

13.

8/22/2007

C:\Documents and Settings\ua02681 UNISOURCE 003\Local Settings\Temporary Internet Files\OLKCE8\PEP Accrual 06 2006

Tucson Electric Power Company
Unclassified Employees Incentive Compensation
J28
June-06

Account 24000-3800	Summary
Balance Required for 2006 PEP Accrual @ 06/30/06	3,349,998 1
Mkt Dept PEP - Paid in Jan for "Guaranteed Home"	(14,324)
Mkt Dept. PEP - Paid in Apr for "Guaranteed Home"	(3,318)
Account 24000-3800 05/31/06 Balance - Preliminary	(2,774,023)
Under / (Over) Accrual	558,333

1-06 Per Michael Daranyi begin 2006 accruing @ 100% TEP employee's @ $5 1 million & Officers at 100% of $1 6 million
2-06 Per Michael Darani - Keep it the same for Feb 2006
3-06 Per Michael Darani - Keep it the same for March 2006 2005 PEP was paid out at $2,278,560 while $2,550,560 was accrued Of the $2,278,560, 600,000 was paid out to officers leaving $1,678,560 pay-out to O&M
4-06 Per Michael Darani - Keep it the same for Apr 2006 -REQUEST TO MOVE TAX PORTION TO EXPENDITURE TYPE 070 - CAME 04/07/06 - INCLUDE THIS CHANGE ON THE APRIL ENTRY
05-06 Per Michael Darani - Keep it the same for May 2006
06-06 Per Michael Darani - Keep it the same for June 2006

Jan 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
Feb 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
Mar 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
Apr 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
May 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
Jun 06 ('$425,000 TEP Unclass + $108,916 TEP Exec + $24,417 UES Exec) =	558,333
	3,349,998 1

Unclassified

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
UNSG	50.0%		0
UNSE	50.0%		0
	100.0%		0
Operation & Maintenance	100.0%	425,000	425,000
Construction & Removal	0.0%		0
	100.0%		425,000

Operation & Maintenance Account Distribution

		FERC Account (location)	Loc Dist *	Dist %	21 57% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	31 37% (003) Distribution	Dist %	47 06% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
					91,673		0		133,323		200,005		0	425,001	
Production		506 IV (300)	72.3%	39.11%	25,927		0	17.93%	23,905	0.30%	600		0	50,432	
		506 SC1 (314)	14.6%		5,235		0		0		0		0	5,235	
		506 SC2 (315)	13.1%		4,697		0		0		0		0	4,697	
Transmission		566			0		0	15.41%	20,545		0		0	20,545	
Distribution		588			0		0	26.48%	35,304	2.25%	4,500		0	39,804	
Customer Accounting & Service		903						5.86%	7,813	5.42%	10,840		0		
								6.16%	8,220	0.53%	1,060		0		
		903			0		0	12.04%	16,052	6.25%	12,500		0	28,552	Combine 903
Administrative & General		920		28.14%	25,797		0	18.53%	24,705	91.05%	182,105		0	232,607	
Production Maintenance		514 IVC (305)	36.0%	32.75%	10,808		0	0 05%	67		0		0	10,875	
		514 SC1 (314)	31.7%		9,517		0		0		0		0	9,517	
		514 SC2 (315)	32.3%		9,697		0		0		0		0	9,697	
Transmission Maintenance		570			0		0	3 72%	4,960	0.00%	0		0	4,960	
Distribution Maintenance		598			0		0	5 85%	7,798	0.06%	120		0	7,919	
Administrative & General Maintenance		935			0		0		0	0.08%	160		0	160	
Total Payroll	Total Operation & Maintenance				91,678		0		133,337		199,985		0	425,000	425,000
Construction & Removal - Acct. 79300														0	
	Total Allocation													425,000	

Officer

Operation & Maintenance / Capital Distribution	Percent	Required Accrual	Allocation
TEP (based on Mass. Formula beginning 2005)	78.86%		105,146
Millennium (based on Mass. Formula beginning 2005)	2.86%		3,813
UNSG (based on Mass. Formula beginning 2005)	9.42%		12,560
UNSE (based on Mass. Formula beginning 2005)	8.86%		11,814 a
	100.0%	133,333.00	133,333
Operation & Maintenance (TEP Only)	100.0%	105,146	105,146
Construction & Removal	0.0%		0
	100.0%		105,146

Operation & Maintenance Account Distribution

	FERC Account (location)	*	Dist %	8 74% (001) Generation	Dist %	0.00% (002) Transmission	Dist %	10.11% (003) Distribution	Dist %	81.15% (004) Corporate	Dist %	0.00% (006) Other	Total	Total Expense By Bus Ctr
	TEP			9,190		0		10,630		85,326		0	105,146	
	500 - GEN			9,190		0		0		0		0	9,190	
	580 - UDC			0		0		10,630		0		0	10,630	
	920 - SSU			0		0		0		85,326		0	85,326	
Total Payroll				9,190		0		10,630		85,326		0	105,146	105,146
Total Allocation													105,146	

Account 21150-3306

Payroll Tax accrual required @ 06/30/06 for 2006 TEP PEP accrual	2	2,550,000	x	7.65%	=	195,075								
Preliminary Balance in A/C 21150 - 3306 (05/31/06)						(162,563)								
Under / (Over) Accrual						32,512								
				Unclassified		32,512		7,013		0		10,200		15,299	0	32,512
				Officer***		0		0		0		0		0	0	0
																32,512

FICA	7 85%	6 2% SS plus 1 45% Medicare
FUTA / SUTA	0.00%	Zero since not an incremental cost
WC	0 00%	Zero since not an incremental cost
	7.85%	

Jan 06 ('$425,000 TEP Unclass) =	425,000
Feb 06 ('$425,000 TEP Unclass) =	425,000
Mar 06 ('$425,000 TEP Unclass) =	425,000
Apr 06 ('$425,000 TEP Unclass) =	425,000
May 06 ('$425,000 TEP Unclass) =	425,000
Jun 06 ('$425,000 TEP Unclass) =	425,000
	2,550,000 2

I/C Statement Impact	
TEP	562,656.00
UNSE	11,814 00
UNSG	12,560.00
MEH	3,813.00
ck figure	590,845.00

* Determined based on P/R by Function Report-Detail by Location for 2004
**See January 2006 journal for detailed back up of business center/distribution percentages
***Per L Joyce stopped accruing Payroll Taxes on Officer portion in May-05

14.

UNSE(0783)11686

ALL-STATE LEGAL®
EXHIBIT
S-43
Admitted

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.41 Incentive Compensation. Refer to Mr. Dukes' rebuttal testimony at page 9.

a. Please quantify and explain fully and in detail Mr. Dukes' rationale for his statement that "The most direct savings result from because PEP is not part of base compensation; therefore employee costs such as vacation pay, sick pay, long term disability, 401K matching, pension expense and other post-retirement benefits that are based on base pay are all reduced."

b. Please confirm that employee base salaries were not reduced when PEP was initially implemented. If this cannot be confirmed, please explain fully why not.

c. Please identify all annual increases in base pay since PEP was first implemented.

d. Please identify the annual amounts of cost for each of the following employee benefits (in total and the amount charged to O&M expense) in each year since PEP was initially implemented:

i. vacation pay,

ii. sick pay,

iii. long term disability,

iv. 401K matching,

v. pension expense

vi. and other post-retirement benefits

RESPONSE:

a. UNS Electric and Tucson Electric Company must attract and retain talented employees to continue to provide service to its customers. To do so, the Companies must pay competitive wages in the form of total compensation and a part of that equation is cash compensation. This is currently accomplished by providing a competitive benefits package and targeting the median of market for total cash compensation. A portion of that total cash compensation is at-risk pay in the form of variable pay for each non-union employee. If that total cash compensation were paid in the form of base pay only, the cost of vacation pay, sick pay, long term disability, 401K matching, pension expense and other post-retirement benefits would all increase, because all of those benefits

are based upon base salary; thus increasing benefit cost and total compensation expense.

b. It was not necessary to reduce the base salaries of the UNS Electric employees retained from Citizens Communications Company, because their base salaries were significantly below the median of market. With the addition of PEP, the employees total cash compensation was still below the median of market.

c. Base pay increases for UNS Electric employees eligible for PEP:

10/01/2003	3.5%
01/01/2005	3.0%
01/01/2006	3.0%
01/01/2007	3.0%

d. Please see the STF 20.41 (d) on the enclosed CD for the annual amounts of cost for employee benefits.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

UNS Electric, Inc.
STF 20.41 (d) - Incentive Compensation - Employee Benefits

	2006	2005	2004	2003
i & ii: Vacation & Sick Pay	831,193.05	873,648.10	298,040.98	110,010.65
iii: Long Term Disability	159,866.44	150,678.47	141,012.09	41,256.00
iv: 401K matching	202,650.20	166,786.67	138,008.16	41,465.73
v: Pension Expense	583,765.42	587,634.96	588,291.00	198,622.00
vi: Other Post-Retirement Benefits	34,076.04	15,999.96	5,250.00	0.00

UNS Electric, Inc.
STF 20.41 (d) - Incentive Compensation - Employee Benefits
Year Ending December 31, 2006

Co	Acct	Exp Type	Exp Type Description	FERC	DR	CR	Net Amount
033	88020	040	Paid Absences	0416	78.60		78.60
033	88030	040	Paid Absences	0417	1,044.31		1,044.31
033	50000	040	Paid Absences	0546	7,119.64		7,119.64
033	50000	040	Paid Absences	0548	767.58		767.58
033	50000	040	Paid Absences	0549		11.00	(11.00)
033	50000	040	Paid Absences	0551	6,174.52		6,174.52
033	50000	040	Paid Absences	0553	13,182.70		13,182.70
033	50000	040	Paid Absences	0554	6,342.55		6,342.55
033	50000	040	Paid Absences	0557	11,833.46		11,833.46
033	50000	040	Paid Absences	0561	5,875.49		5,875.49
033	50000	040	Paid Absences	0562	1,807.95		1,807.95
033	50000	040	Paid Absences	0563	48.17		48.17
033	50000	040	Paid Absences	0566	1,132.66		1,132.66
033	50000	040	Paid Absences	0570	522.46		522.46
033	50000	040	Paid Absences	0571	345.61		345.61
033	50000	040	Paid Absences	0580	3,749.02		3,749.02
033	50000	040	Paid Absences	0581	37,335.69		37,335.69
033	50000	040	Paid Absences	0582	4,353.31		4,353.31
033	50000	040	Paid Absences	0583	19,770.13		19,770.13
033	50000	040	Paid Absences	0584	34,166.79		34,166.79
033	50000	040	Paid Absences	0585	114.54		114.54
033	50000	040	Paid Absences	0586	67,340.91		67,340.91
033	50000	040	Paid Absences	0587	911.01		911.01
033	50000	040	Paid Absences	0588	17,574.60		17,574.60
033	50000	040	Paid Absences	0590	6,145.66		6,145.66
033	50000	040	Paid Absences	0592	37,628.88		37,628.88
033	50000	040	Paid Absences	0593	50,958.87		50,958.87
033	50000	040	Paid Absences	0594	4,555.32		4,555.32
033	50000	040	Paid Absences	0595	8,386.42		8,386.42
033	50000	040	Paid Absences	0596	2,267.14		2,267.14
033	50000	040	Paid Absences	0597		25.00	(25.00)
033	50000	040	Paid Absences	0598	13.96		13.96
033	50000	040	Paid Absences	0901	19,037.20		19,037.20
033	50000	040	Paid Absences	0902	9,318.80		9,318.80
033	50000	040	Paid Absences	0903	91,631.14		91,631.14
033	50000	040	Paid Absences	0905	1,607.25		1,607.25
033	50000	040	Paid Absences	0908	10,470.24		10,470.24
033	50000	040	Paid Absences	0909	5,736.74		5,736.74
033	50000	040	Paid Absences	0910	137.40		137.40
033	50000	040	Paid Absences	0920	1,802.66		1,802.66
033	50000	040	Paid Absences	0920	186,365.36		186,365.36
033	52100	040	Paid Absences	0923	112,293.14		112,293.14
033	50000	040	Paid Absences	0925	7,962.70		7,962.70
033	50000	040	Paid Absences	0926	10,473.92		10,473.92
033	50000	040	Paid Absences	0930	14,679.88		14,679.88
033	50000	040	Paid Absences	5612	8,164.67		8,164.67
	Sum	040	Paid Absences		831,229.05	36.00	831,193.05
033	70530	084	Life Insurance/LT Disability	0926	159,866.44		159,866.44
	Sum	084	Life Insurance/LT Disability		159,866.44		159,866.44
033	70510	081	401K	0926	202,650.20		202,650.20
	Sum	081	401K		202,650.20		202,650.20
033	70500	080	Pensions	0926	583,765.42		583,765.42
	Sum	080	Pensions		583,765.42		583,765.42
033	70520	082	Medical Insurance / (Post Retirement Exp Portion)	0926	34,076.04		34,076.04
	Sum	080	Medical Insurance / (Post Retirement Exp Portion)		34,076.04		34,076.04

Source: Transaction Detail Query - GL Period: %06, Company: 033, Exp Type: 040, 080, 081, 084, 082

UNS Electric, Inc.
STF 20.41 (d) - Incentive Compensation - Employee Benefits
Year Ending December 31, 2005

Co	Acct	Exp Type	Exp Type Description	FERC	DR	CR	Net Amount
033	50000	040	Paid Absences	0416		78.01	(78.01)
033	88020	040	Paid Absences	0416	78.01		78.01
033	88020	040	Paid Absences	0416		20.74	(20.74)
033	88030	040	Paid Absences	0417	27.90		27.90
033	50000	040	Paid Absences	0546	1,687.66		1,687.66
033	50000	040	Paid Absences	0548	737.76		737.76
033	50000	040	Paid Absences	0549	101.77		101.77
033	50000	040	Paid Absences	0551	6,076.82		6,076.82
033	50000	040	Paid Absences	0553	12,622.77		12,622.77
033	50000	040	Paid Absences	0554	7,064.81		7,064.81
033	50000	040	Paid Absences	0557	6,510.55		6,510.55
033	50000	040	Paid Absences	0561	4,803.10		4,803.10
033	50000	040	Paid Absences	0562	2,670.69		2,670.69
033	50000	040	Paid Absences	0563	382.06		382.06
033	50000	040	Paid Absences	0566	1,614.84		1,614.84
033	50000	040	Paid Absences	0570	1,601.98		1,601.98
033	50000	040	Paid Absences	0571	242.65		242.65
033	50000	040	Paid Absences	0580	8,276.85		8,276.85
033	50000	040	Paid Absences	0581	37,863.20		37,863.20
033	50000	040	Paid Absences	0582	1,082.70		1,082.70
033	50000	040	Paid Absences	0583	18,994.29		18,994.29
033	50000	040	Paid Absences	0584	35,071.70		35,071.70
033	50000	040	Paid Absences	0585	115.74		115.74
033	50000	040	Paid Absences	0586	60,560.31		60,560.31
033	50000	040	Paid Absences	0587	858.23		858.23
033	50000	040	Paid Absences	0588	25,713.24		25,713.24
033	50000	040	Paid Absences	0590	6,082.40		6,082.40
033	50000	040	Paid Absences	0592	33,198.14		33,198.14
033	50000	040	Paid Absences	0593	63,074.62		63,074.62
033	50000	040	Paid Absences	0594	13,972.34		13,972.34
033	50000	040	Paid Absences	0595	7,202.42		7,202.42
033	50000	040	Paid Absences	0596	6,233.42		6,233.42
033	50000	040	Paid Absences	0597	223.88		223.88
033	50000	040	Paid Absences	0598	93.41		93.41
033	50000	040	Paid Absences	0901	20,777.07		20,777.07
033	50000	040	Paid Absences	0902	9,650.73		9,650.73
033	50000	040	Paid Absences	0903	105,693.51		105,693.51
033	50000	040	Paid Absences	0905	1,062.37		1,062.37
033	50000	040	Paid Absences	0908	8,376.93		8,376.93
033	50000	040	Paid Absences	0909	9,008.01		9,008.01
033	50000	040	Paid Absences	0910	86.37		86.37
033	50000	040	Paid Absences	0920	125,564.21		125,564.21
033	52100	040	Paid Absences	0923	184,507.76		184,507.76
033	50000	040	Paid Absences	0925	1,909.44		1,909.44
033	50000	040	Paid Absences	0926	9,619.60		9,619.60
033	50000	040	Paid Absences	0930	32,650.59		32,650.59
	Sum	040	Paid Absences		873,746.85	98.75	873,648.10
033	70530	084	Life Insurance/LT Disability	0926		159.24	(159.24)
033	70530	084	Life Insurance/LT Disability	0926	150,977.71		150,977.71
033	70530	084	Life Insurance/LT Disability	0926		140.00	(140.00)
	Sum	084	Life Insurance/LT Disability		150,977.71	299.24	150,678.47
033	70510	081	401K	0926	166,786.67		166,786.67
	Sum	081	401K		166,786.67		166,786.67
033	70500	080	Pensions	0926	587,634.96		587,634.96
	Sum	080	Pensions		587,634.96		587,634.96
033	70520	082	Medical Insurance / (Post Retirement Exp Portion)	0926	15,999.96		15,999.96
	Sum	080	Medical Insurance / (Post Retirement Exp Portion)		15,999.96		15,999.96

Source: Transaction Detail Query - GL Period: %05, Company: 033, Exp Type: 040, 080, 081, 084, 082

UNS Electric, Inc.
STF 20.41 (d) - Incentive Compensation - Employee Benefits
Year Ending December 31, 2004

Co	Acct	Exp Type	Exp Type Description	FERC	DR	CR	Net Amount
033	50000	040	Paid Absences	0557	9,127.05		9,127.05
033	50000	040	Paid Absences	0561	1,967.24		1,967.24
033	50000	040	Paid Absences	0562	35.86		35.86
033	50000	040	Paid Absences	0566	180.68		180.68
033	50000	040	Paid Absences	0570	392.19		392.19
033	50000	040	Paid Absences	0580	13,818.31		13,818.31
033	50000	040	Paid Absences	0583	685.35		685.35
033	50000	040	Paid Absences	0588	8,715.84		8,715.84
033	50000	040	Paid Absences	0592	9,091.26		9,091.26
033	50000	040	Paid Absences	0595	5,650.59		5,650.59
033	50000	040	Paid Absences	0901	4,060.87		4,060.87
033	50000	040	Paid Absences	0902	790.32		790.32
033	50000	040	Paid Absences	0903	15,326.27		15,326.27
033	50000	040	Paid Absences	0908	624.05		624.05
033	50000	040	Paid Absences	0909	3,777.93		3,777.93
033	50000	040	Paid Absences	0920	20,339.48		20,339.48
033	50000	040	Paid Absences	0925	780.36		780.36
033	50000	040	Paid Absences	0926	11,197.34		11,197.34
033	50000	040	Paid Absences	0930	1,618.88		1,618.88
033	52100	040	Paid Absences	0923	189,861.11		189,861.11
	Sum	040	Paid Absences		298,040.98		298,040.98
033	70530	084	Life Insurance/LT Disability	0926	141,012.09		141,012.09
	Sum	084	Life Insurance/LT Disability		141,012.09		141,012.09
033	70510	081	401K	0926	138,008.16		138,008.16
	Sum	081	401K		138,008.16		138,008.16
033	70500	080	Pensions	0926	588,291.00		588,291.00
	Sum	080	Pensions		588,291.00		588,291.00
033	70520	082	Medical Insurance / (Post Retirement Exp Portion)	0926	5,250.00		5,250.00
	Sum	080	Medical Insurance / (Post Retirement Exp Portion)		5,250.00		5,250.00

Source: Transaction Detail Query - GL Period: %04, Company: 033, Exp Type: 040, 080, 081, 084, 082

UNS Electric, Inc.
STF 20.41 (d) - Incentive Compensation - Employee Benefits
Year Ending December 31, 2003

Co	Acct	Exp Type	Exp Type Description	FERC	DR	CR	Net Amount
033	50000	040	Paid Absences	0557	7.65		7.65
033	50000	040	Paid Absences	0557	1,690.61		1,690.61
033	50000	040	Paid Absences	0580	2,627.85		2,627.85
033	50000	040	Paid Absences	0583	797.24		797.24
033	50000	040	Paid Absences	0588	14.81		14.81
033	50000	040	Paid Absences	0592	3,107.79		3,107.79
033	50000	040	Paid Absences	0595	1,189.48		1,189.48
033	50000	040	Paid Absences	0901	517.94		517.94
033	50000	040	Paid Absences	0902	0.00		0.00
033	50000	040	Paid Absences	0903	1,280.25		1,280.25
033	50000	040	Paid Absences	0905	105.60		105.60
033	50000	040	Paid Absences	0908	1,175.74		1,175.74
033	50000	040	Paid Absences	0909	1,491.27		1,491.27
033	50000	040	Paid Absences	0920	9,553.95		9,553.95
033	50000	040	Paid Absences	0925	318.02		318.02
033	50000	040	Paid Absences	0926	11,508.53		11,508.53
033	50000	040	Paid Absences	0930	1,134.71		1,134.71
033	52100	040	Paid Absences	0923	73,489.21		73,489.21
	Sum	040	Paid Absences		110,010.65		110,010.65
033	70530	084	Life Insurance/LT Disability	0926	42,374.15	1,118.15	41,256.00
	Sum	084	Life Insurance/LT Disability		42,374.15	1,118.15	41,256.00
033	70510	081	401K	0926	41,465.73		41,465.73
	Sum	081	401K		41,465.73		41,465.73
033	70500	080	Pensions	0926	205,430.00	6,808.00	198,622.00
	Sum	080	Pensions		205,430.00	6,808.00	198,622.00
033	70520	082	Medical Insurance / (Post Retirement Exp Portion)	0926			
	Sum	080	Medical Insurance / (Post Retirement Exp Portion)		0.00		0.00

Source: Journal Entry Summary Query - GL Period: %03, Company: 033, Exp Type: 040, 080, 081, 084, 082

EXHIBIT
S-44
Submitted

UNS ELECTRIC, INC.'S RESPONSES TO STAFF'S TENTH SET OF DATA REQUESTS DOCKET NO. E-04204A-06-0783 June 11, 2007

STF 10.11 Please list by amount and account all stock based compensation expense charged to UNS Electric during the test year, including but not limited to executive stock options, the 2006 Omnibus Stock and Incentive Plan, performance share awards, accruals made pursuant to SFAS 123R and any other stock based compensation awards that resulted in costs being charged to UNS Electric during the test year.

a. Also, provide a description of each distinct stock based compensation program that resulted in charges to UNS Electric during the test year.

RESPONSE: Stock based compensation expense charged to UNS Electric during the test year is as follows:

Stock Option Expense

FERC 923	$ 62,904

Performance Share Expense

FERC 923	$ 19,969

Director Stock Award Expense

FERC 930	$ 45,895

Dividend Equivalents on Stock Options & Stock Units

FERC 920	$ 186
FERC 923	$ 33,623
FERC 930	$ (795)
Total	$ 33,014

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 11, 2007

a. During the test year, Performance Shares and Nonqualified Stock Options were used in the compensation program. Please see STF 10.11, Bates Nos. UNSE(0783)08874 to UNSE(0783)08898, on the enclosed CD for a detailed description of each distinct stock based compensation program that resulted in charges to UNS Electric during the test year.

RESPONDENT: Amy Teller
Human Resources (a)

WITNESS: Karen Kissinger
Dallas Dukes (a)

UNISOURCE ENERGY CORPORATION
2006 Omnibus Stock and Incentive Plan

UNSE(0783)08874

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UNISOURCE ENERGY CORPORATION
2006 OMNIBUS STOCK AND INCENTIVE PLAN

ARTICLE I
Establishment, Purpose, and Effective Date of Plan

1.1. Establishment. Subject to the approval of the shareholders of UniSource Energy Corporation, an Arizona corporation ("UniSource" or the "Company"), the Company has established the UniSource Energy Corporation 2006 Omnibus Stock and Incentive Plan (the "Plan"), as set forth herein, effective as of January 1, 2006. The Plan supercedes and replaces the UniSource Energy Corporation 1994 Omnibus Stock and Incentive Plan (the "1994 Omnibus Plan") and the UniSource Energy Corporation Amended and Restated 1994 Outside Directors Stock Option Plan (the "1994 Directors Plan"), and all other prior equity compensation plans or programs maintained by the Company; provided, however, that the 1994 Omnibus Plan, the 1994 Directors Plan and any prior stock option plans of the Company shall remain nominally in effect until all stock options granted under such prior plans have been exercised, forfeited, canceled, expired or otherwise terminated in accordance with the terms of such grants.

1.2. Purpose. The Plan is intended to provide certain present and future employees, directors and consultants stock based incentives and other equity interests in the Company, thereby giving them a stake in the growth and prosperity of the Company and encouraging the continuance of their services with the Company or its subsidiaries.

1.3. Effective Date. The Plan is effective January 1, 2006, subject to approval by the shareholders of the Company.

ARTICLE II
Definitions

Whenever used herein, the following terms shall have their respective meanings set forth below.

2.1. "Award" means any Option, Stock Appreciation Right, Restricted Stock, Stock Unit, Performance Unit or Performance Share granted under this Plan.

2.2. "Award Agreement" means a written agreement between the Company and each Participant that sets forth the terms and provisions applicable to an Award granted to the Participant under the Plan, and is a condition to the grant of an Award hereunder.

2.3. "Board" means the Board of Directors of the Company.

2.4. "Change in Control" means and shall be deemed to have occurred, except as otherwise provided in an applicable Award Agreement, as of the date of the first to occur of the following events:

(a) any Person or Group acquires stock of the Company that, together with stock held by such Person or Group, constitutes more than 50% of the total Fair Market Value or total voting power of the stock of the Company. However, if any Person or Group is considered to own more than 50% of the total Fair Market Value or total voting power of the stock of the Company, the acquisition of additional stock by the same Person or Group is not considered to cause a Change in Control of the Company. An increase in the percentage of stock owned by any Person or Group as a result of a transaction in which the Company acquires its stock in exchange for property will be treated as an acquisition of stock for purposes of this subsection. This subsection applies only when there is a transfer of stock of the Company (or issuance of stock of the Company) and stock in the Company remains outstanding after the transaction;

(b) any Person or Group acquires (or has acquired during the 12-month period ending on the date of the most recent acquisition by such Person or Group) ownership of stock of the Company possessing 35% or more of the total voting power of the stock of the Company;

(c) a majority of members of the Company's Board is replaced during any 12-month period by Directors whose appointment or election is not endorsed by a majority of the members of the Company's Board prior to the date of the appointment or election; or

(d) any Person or Group acquires (or has acquired during the 12-month period ending on the date of the most recent acquisition by such Person or Group) assets from the Company that have a total gross fair market value equal to or more than 40% of the total gross fair market value of all of the assets of the Company immediately prior to such acquisition or acquisitions. For this purpose, gross fair market value means the value of the assets of the Company, or the value of the assets being disposed of, determined without regard to any liabilities associated with such assets. However, no Change in Control shall be deemed to occur under this subsection (d) as a result of a transfer to:

(i) A shareholder of the Company (immediately before the asset transfer) in exchange for or with respect to its stock;

(ii) An entity, 50% or more of the total value or voting power of which is owned, directly or indirectly, by the Company;

(iii) A Person or Group that owns, directly or indirectly, 50% or more of the total value or voting power of all the outstanding stock of the Company; or

(iv) An entity, at least 50% of the total value or voting power of which is owned, directly or indirectly, by a person described in clause (iii) above.

For these purposes, the term "Person" shall mean an individual, corporation, association, joint stock company, business trust or other similar organization, partnership, limited liability company, joint venture, trust, unincorporated organization or government or agency, instrumentality or political subdivision thereof. The term "Group" shall have the meaning set forth in Rule13d-5 of the Securities Exchange Commission ("SEC"), modified to the extent

necessary to comply with Proposed Treasury Regulation Section 1.409A-3(g)(5)(v)(B), or any successor thereto in effect at the time a determination of whether a Change in Control has occurred is being made. If any one Person, or Persons acting as a Group, is considered to effectively control the Corporation as described in subsections (b) or (c) above, the acquisition of additional control by the same Person or Persons is not considered to cause a Change in Control.

2.5. "Code" means the Internal Revenue Code of 1986, as amended.

2.6. "Committee" means the Compensation Committee of the Board, or such other person or persons as the Board shall designate to administer the Plan, as provided in Article III.

2.7. "Company" means UniSource Energy Corporation, an Arizona Corporation and (except for purposes of determining whether a Change in Control has occurred) any successor corporation.

2.8. "Director" means any individual who is a member of the Board, who is not also an Employee.

2.9. "Disability" means that a Participant who is an Employee (a) is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or to last for a continuous period of not less than 12 months; (b) is, by reason of any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, receiving income replacement benefits for a period of not less than 3 months under an accident and health plan covering employees of the Company; or (c) has been determined to be totally disabled by the Social Security Administration.

2.10. "Employee" means any full-time or part-time employee of the Company or one of its Subsidiaries (including any officer or Director who is also an employee).

2.11. "Fair Market Value" means the average of the highest and lowest sales prices of the Stock as reported on the consolidated tape for securities listed on the New York Stock Exchange ("NYSE") (or, if the Stock is not listed on the NYSE, such other established securities market on which the Stock is traded) on a particular date. In the event that there are no Stock transactions on such date, the Fair Market Value shall be determined by utilization of the above formula as of the immediately preceding date on which there were Stock transactions.

2.12. "Incentive Stock Option" or "ISO" means the right to purchase Stock pursuant to terms and conditions that provide that such right will be treated as an incentive stock option within the meaning of Code Section 422, as described in Article VI.

2.13. "Named Executive Officer" means a Participant who is one of the group of covered employees as defined in the regulations promulgated under Code Section 162(m), or any successor provision or statute.

2.14. "Nonqualified Stock Option" or "NQSO" means the right to purchase Stock pursuant to terms and conditions that provide that such right will not be treated as an Incentive Stock Option, as described in Article VI.

2.15. "Non-Tandem SAR" means an SAR that is granted independently of any Options, as described in Article VII.

2.16. "Option" means the right to purchase Stock at a stated price for a specified period of time. For purposes of the Plan, an Option may be either an Incentive Stock Option or a Nonqualified Stock Option.

2.17. "Participant" means an Employee, prospective Employee, Director or consultant who has outstanding an Award granted under the Plan, and includes those former Employees, Directors or consultants who have certain post-termination rights under the terms of an Award granted under the Plan.

2.18. "Performance-Based Exception" means the exception for performance-based compensation from the tax deductibility limitations of Code Section 162(m).

2.19. "Performance Share" means an Award granted to a Participant as described in Article IX.

2.20. "Performance Unit" means an Award granted to a Participant as described in Article IX.

2.21. "Period of Restriction" means the period during which shares of Restricted Stock are subject to restrictions pursuant to Article VIII of the Plan, or the period during which Performance Shares or Performance Units are subject to restrictions pursuant to Article IX of the Plan.

2.22. "Plan" means the UniSource Energy Corporation 2006 Omnibus Stock and Incentive Plan, as set forth herein.

2.23. "Restricted Stock" means an Award of Stock that is subject to forfeiture if the Participant does not satisfy the restrictions specified in the Award Agreement applicable to such Restricted Stock, granted to a Participant pursuant to Article VIII of the Plan.

2.24. "Retirement" (including "Early Retirement" and "Normal Retirement") means, with respect to an Employee, Termination of Service of the Employee after he or she has become eligible for an immediate early, normal or late retirement benefit under the terms of a defined benefit pension plan sponsored by the Company and applicable to such Employee.

2.25. "Share" means a share of Stock.

2.26. "Stock" means the Common Stock of the Company, no par value.

2.27. "Stock Appreciation Right" and "SAR" mean the right to receive a payment from the Company equal to the excess of the Fair Market Value of a share of Stock at the date of exercise over a specified price fixed by the Committee in the Award Agreement, which shall not be less than 100% of the Fair Market Value of the Stock on the date of grant. In the case of a Stock Appreciation Right which is granted in conjunction with an Option, the specified price shall be the Option exercise price.

2.28. "Stock Unit" means a non-voting unit of measurement which is deemed for bookkeeping purposes to be equivalent to one outstanding share of Stock (subject to adjustment), granted to a Participant pursuant to Article VIII of the Plan.

2.29. "Subsidiary" means any corporation, partnership, joint venture, affiliate, or other entity in which the Company is at least a majority-owner of all issued and outstanding equity interests or has a controlling interest.

2.30. "Tandem SAR" means a SAR that is granted in connection with a related Option pursuant to Article VII, the exercise of which shall require forfeiture of the right to purchase a Share under the related Option (and when a Share is purchased under the Option, the Tandem SAR shall similarly be forfeited).

2.31. "Termination of Service" means the cessation of performance of services for the Company, as determined by the Committee. For this purpose, transfer of a Participant among the Company and any Subsidiary, or transfer from a position as Director or consultant to Employee, shall not be considered a Termination of Service with the Company. Whether an Employee, Director or consultant incurs a Termination of Service in respect of an Award subject to Code Section 409A will be determined in accordance with the requirements thereof.

ARTICLE III
Administration

3.1. Administration. The Committee shall be responsible for the administration of the Plan. The Compensation Committee, or other committee appointed to administer the Plan, shall consist of not less than two Directors of the Company who are "non-employee directors" within the meaning of Rule 16b-3 of the Securities Exchange Act of 1934, "outside directors" within the meaning of Code Section 162(m) and regulations thereunder, and "independent directors" as described in the NYSE's Listed Company Manual, as each such rule or regulation is in effect from time to time. The Board may, from time to time, remove members from, or add members to, the Committee. Any vacancies on the Committee shall be filled by members of the Board. The foregoing notwithstanding, the Board shall perform the functions of the Committee for purposes of granting Awards to non-Employee Directors.

3.2. Actions of the Committee. A majority of the members of the Committee shall constitute a quorum. The Committee may act at a meeting, including a telephonic meeting, by action of a majority of the members present, or without a meeting by unanimous written consent.

3.3. Authority of the Committee. The Committee is authorized to interpret the Plan and any Award Agreement issued under the Plan, the 1994 Omnibus Plan and the 1994 Directors Plan; to prescribe, amend, and rescind rules and regulations relating to the Plan; to provide for conditions and assurances deemed necessary or advisable to protect the interests of the Company; and to make all other determinations necessary or advisable for the administration of the Plan, but only to the extent not contrary to the express provisions of the Plan. Determinations, interpretations, or other actions made or taken by the Committee in good faith pursuant to the provisions of the Plan shall be final, binding and conclusive for all purposes and upon all persons whomsoever. In addition, the Committee may prescribe, amend and rescind

such rules and regulations as may be necessary or appropriate to permit the participation of Participants in foreign jurisdictions (*e.g.*, rules for the conversion of currency and compliance with applicable securities laws).

The Committee shall have the authority, subject to the express provisions of the Plan, in its discretion, (a) to determine the Employees, Directors and consultants to whom Awards shall be granted; (b) to determine the times when such Awards shall be granted, the size and type of Awards, the purchase price or exercise price of Awards, the period(s) during which such Awards shall be exercisable (whether in whole or in part), and the any other terms, restrictions and conditions applicable to Awards (which need not be identical); and (c) to amend or modify any outstanding Awards under the Plan, the 1994 Omnibus Plan and the 1994 Directors Plan, to the extent the terms of such Award are within the discretion of the Committee as provided under the Plan, the 1994 Omnibus Plan or the 1994 Directors Plan, as applicable, subject to Section 14.1. As permitted by law, the Committee may delegate any authority granted to it herein.

Notwithstanding the provisions hereof regarding the term of this Plan, all authority of the Board and the Committee with respect to Awards hereunder, including the authority to amend outstanding Awards, shall continue after the term of this Plan, so long as any Award remains outstanding.

ARTICLE IV
Stock Subject to Plan

4.1. Number. The shares to be delivered under the Plan may consist, in whole or in part, of authorized but unissued Stock or treasury Stock, not reserved for any other purpose. Subject to adjustment as provided in Section 4.3, a total of Two Million Two Hundred Fifty Thousand (2,250,000) Shares shall be authorized for issuance or to be used for reference purposes pursuant to Awards granted under the Plan. Any Shares issued or used for reference purposes in connection with Awards other than Options and Stock Appreciation Rights shall be counted against the Share limit described in the preceding sentence as three (3) Shares for every one Share issued in connection with such Award or by which the Award is valued by reference; and any Shares issued or used for reference purposes in connection with Awards of Options and Stock Appreciation Rights shall be counted against the Share limit described in the preceding sentence as one Share for every one Share issued in connection with such Award or by which the Award is valued by reference. In addition to the above aggregate limitation:

(a) No Participant under this Plan shall be granted Options, Stock Appreciation Rights or other Awards in any 36-month period covering more than Seven Hundred Fifty Thousand (750,000) Shares.

(b) No Participant under this Plan shall be granted a cash award in settlement of Performance Units in excess of Two Million Dollars ($2,000,000) in any 12 month period.

(c) The maximum number of Shares that may be issued under the Plan as Incentive Stock Options is Two Million Two Hundred Fifty Thousand (2,250,000).

4.2. Lapsed Awards. In the event any Awards granted under this Plan, or under the 1994 Omnibus Plan or the 1994 Directors Plan and outstanding on January 1, 2006, shall be forfeited, terminate, be canceled or expire, the number of Shares subject to such Award, to the extent of any such forfeiture, termination, cancellation or expiration, shall thereafter again be available for grant under the Plan; provided, however, that in the case of Awards other than Options and Stock Appreciation Rights, [three (3)] Shares shall thereafter again be available for grant under the Plan for every one Share issued in connection with such Award or by which the Award was valued by reference. In addition, if Shares are not delivered pursuant to a Stock Unit or Performance Unit Award or a SAR Award that is not related to an Option, because the Award is paid in cash, such Shares shall not be deemed to have been delivered for purposes of determining the maximum number of Shares available for delivery under the Plan. However, Shares tendered or withheld for payment of an Option exercise price or for tax withholding, and Shares not issued upon settlement of a SAR in Stock will not increase the number of Shares available for grant under the Plan.

4.3. Adjustment in Capitalization. In the event of any change in corporate capitalization, such as a stock split, or a corporate transaction, such as any merger, consolidation, separation, including a spin-off, or other distribution of stock or property of the Company, extraordinary cash dividend, any reorganization (whether or not such reorganization comes within the definition of such term in Code Section 368) or any partial or complete liquidation of the Company, an adjustment shall be made in the number and class of Shares available for Awards, the number and class of and/or price of Shares subject to outstanding Awards granted under the Plan and the number of Shares set forth in Sections 4.1 and 4.2, as may be determined to be appropriate and equitable by the Committee, in its sole discretion, to prevent dilution or enlargement of rights; provided, however, that the number of Shares subject to any Award shall always be a whole number by rounding any fractional Share to the nearest whole Share.

4.4. Replacement Awards. In the event of any corporate transaction in which the Company or a Subsidiary acquires a corporate entity which, at the time of such transaction, maintains an equity compensation plan pursuant to which awards of stock options, stock appreciation rights, performance shares, performance units or restricted stock are then outstanding (the "acquired plan"), the Committee may, in its discretion, make Awards under this Plan to assume, substitute or convert such outstanding awards in such manner as may be determined to be appropriate and equitable by the Committee, in its sole discretion, to prevent dilution or enlargement of rights; provided, however, that the number of Shares subject to any Award shall always be a whole number by rounding any fractional Share to the nearest whole Share. Options or SARs issued pursuant to this Section 4.4 shall not be subject to the requirement that the exercise price of such Award not be less than the Fair Market Value of Stock on the date the Award is granted. Shares used in connection with an Award granted in substitution for an award outstanding under an acquired plan under this Section 4.4 shall not be counted against the number of Shares reserved under this Plan under Section 4.1. Any shares authorized and available for issuance under the acquired plan shall, subject to adjustment as described in Section 4.3, be available for use in making Awards under this Plan with respect to persons eligible under such acquired plan, by virtue of the Company's assumption of such acquired plan, consistent with Rule 303A(8) of the NYSE Listed Company Manual.

ARTICLE V
Duration of Plan

5.1. Duration of Plan. The Plan shall remain in effect, subject to the right of the Company's Board of Directors to amend or terminate the Plan at any time pursuant to Section 14.1, until all Shares subject to the Plan shall have been purchased or granted according to the Plan's provisions. However, in no event may an Award be granted under the Plan on or after January 1, 2016. Any Awards granted under the Plan prior to January 1, 2016 shall continue in effect until they expire, terminate, are exercised or are paid in full.

ARTICLE VI
Stock Options

6.1. Grant of Options. Subject to the terms and provisions of the Plan, Options may be granted to one or more Participants in such number, upon such terms and provisions, and at any time and from time to time, as determined by the Committee in its sole discretion. The Committee may grant either Nonqualified Stock Options or Incentive Stock Options and shall have complete discretion in determining the number of Options of each granted to each Participant, subject to the limitations of Article IV.

6.2. Limitations on Incentive Stock Options. To the extent the aggregate Fair Market Value (determined at the time the Option is granted) of the Stock with respect to which Incentive Stock Options are exercisable for the first time by a Participant in any calendar year (under this Plan and any other plans of the Company) exceeds $100,000, such Options shall not be deemed Incentive Stock Options. Any ISOs that become exercisable in excess of such amount shall be deemed NQSOs to the extent of such excess. In determining which Options may be treated as NQSOs under the preceding sentence, Options will be taken into account in the order of their dates of grant. Nothing in this Section 6.2 of the Plan shall be deemed to prevent the grant of NQSOs in amounts which exceed the maximum on ISOs established by Code Section 422.

6.3. Option Award Agreement. Each Option shall be evidenced by an Award Agreement that shall specify the type of Option granted, the Option price, the duration of the Option, the number of shares of Stock to which the Option pertains, and such other terms and conditions (which need not be identical among Participants) as the Committee shall determine in its sole discretion; provided, however, that no cash dividends or dividend equivalents shall be paid or provided with respect to Options. The Award Agreement shall specify whether the Option is to be treated as an ISO within the meaning of Code Section 422. If such Option is not designated as an ISO, such Option shall be deemed a NQSO.

6.4. Exercise Price. Except as otherwise provided in Section 4.4 with respect to replacement Awards, no Option shall be granted pursuant to the Plan at an exercise price that is less than the Fair Market Value of the Stock on the date the Option is granted. With respect to a Participant who owns, directly or indirectly, more than 10% of the total combined voting power of all classes of the stock of the Company or any Subsidiary, the exercise price of Incentive Stock Options shall be at least 110% of the Fair Market Value of Stock on the ISO's grant date. Notwithstanding any other provision in the Plan to the contrary, an Option may not be amended

or modified to reduce the exercise price after the Grant Date, and may not be surrendered in consideration of or exchanged for cash, other Awards or a new Option having an exercise price below that of the Option being surrendered or exchanged, except as otherwise provided in Section 4.3 with respect to an adjustment in capitalization, without approval of the Company's shareholders.

6.5. Duration of Options. Each Option shall expire at such time or times as the Committee shall determine at the time it is granted, provided, however, that no Option shall be exercisable later than ten years from the date of its grant. Notwithstanding the foregoing, with respect to ISOs, in the case of a Participant who owns, directly or indirectly, more than 10% of the total combined voting power of all classes of the stock of the Company or any Subsidiary, no ISO shall be exercisable later than the fifth anniversary of the grant date.

6.6. Exercise of Options. Options granted under the Plan shall be exercisable at such time or times and in such manner, and be subject to such restrictions and conditions, as the Committee shall in each instance approve, which need not be the same for all Participants; provided, however, that an Option shall not be exercisable prior to the first anniversary of the date on which the Option was granted, except (in the Committee's discretion) in the case of death, Disability or a Change in Control.

6.7. Payment. The purchase price of Stock upon exercise of any Option shall be paid in full either (a) in cash, (b) in Stock valued at its Fair Market Value on the date of exercise, or (c) by a combination of (a) and (b), at the discretion of the Committee. The Committee, in its sole discretion, may also permit payment of the purchase price upon exercise of any Option to be made by having shares withheld from the total number of shares of common stock to be delivered upon exercise, or by such other method as the Committee shall permit. The proceeds from the payment of Option exercise prices shall be added to the general funds of the Company and shall be used for general corporate purposes.

6.8. Termination of Service. The Committee shall set forth in the applicable Award Agreement the extent to which a Participant shall have the right to exercise the Option or Options following termination of his or her employment, service as a Director, or consulting arrangement with the Company and/or its Subsidiaries. Such provisions shall be in the sole discretion of the Committee, need not be uniform among all Options issued pursuant to the Plan, and may reflect distinctions based on the reasons for such termination, including, but not limited to, termination for cause or good reason, or reasons relating to the breach or threatened breach of restrictive covenants.

6.9. Non-Transferability of Options. No Option granted under the Plan may be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated, otherwise than by will or by the laws of descent and distribution. Further, all Incentive Stock Options and, except as otherwise provided in the applicable Award Agreement, Nonqualified Stock Options, granted to a Participant under the Plan shall be exercisable only by such Participant during his or her lifetime. Notwithstanding the foregoing, the Committee may, in its sole discretion upon application of a Participant, permit the transfer of an Option to a family member or family trust or partnership, or to a charitable organization, provided that no value or consideration is received by the Participant with respect to such transfer.

ARTICLE VII
Stock Appreciation Rights

7.1. Grant of Stock Appreciation Rights. Subject to the terms and provisions of the Plan, Stock Appreciation Rights may be granted to one or more Participants in such number, upon such terms and provisions, and at any time and from time to time, as determined by the Committee in its sole discretion. The Committee may grant Non-Tandem SARs, Tandem SARs, or any combination of these forms of SARs. The Committee shall designate, at the time of grant, the grant price of a Non-Tandem SAR, which grant price shall be at least equal to the Fair Market Value of a Share on the grant date of the SAR, except as otherwise provided in Section 4.4 with respect to replacement awards. The grant price of Tandem SARs shall equal the Option Price of the related Option. Notwithstanding any other provision in the Plan to the contrary, an SAR may not be amended or modified to reduce the grant price after the Grant Date, and may not be surrendered in consideration of or exchanged for cash, other Awards or a new SAR having a grant price below that of the SAR being surrendered or exchanged, except as otherwise provided in Section 4.3 with respect to an adjustment in capitalization, without shareholder approval.

7.2. SAR Award Agreement. Each SAR shall be evidenced by an Award Agreement that shall specify the type of SAR granted, the SAR grant price, the duration of the SAR, the number of shares of Stock to which the Award pertains, and such other terms and conditions (which need not be identical among Participants) as the Committee shall determine in its sole discretion; provided, however, that no cash dividends or dividend equivalents shall be paid or provided with respect to SARs.

7.3. Duration of SAR. The term of an SAR granted under the Plan shall not exceed ten years. Notwithstanding the foregoing, a Tandem SAR shall have the same term as the Option to which it relates.

7.4. Exercise of SARs. SARs granted under the Plan shall be exercisable at such time or times and in such manner, and be subject to such restrictions and conditions, as the Committee shall in each instance approve, which need not be the same for all Participants; provided, however, that a SAR shall not be exercisable prior to the first anniversary of the date on which the SAR was granted, except (in the Committee's discretion) in the case of death, Disability or a Change in Control. Tandem SARs may be exercised for all or part of the Shares subject to the related Option upon the surrender of the right to exercise the equivalent portion of the related Option. A Tandem SAR may be exercised only with respect to the Shares for which its related Option is then exercisable. Notwithstanding any other provision of the Plan to the contrary, with respect to a Tandem SAR granted in connection with an ISO: (a) the Tandem SAR will expire no later than the expiration of the underlying ISO; (b) the value of the payout with respect to the Tandem SAR may be for no more than 100% of the difference between the Option exercise price of the underlying ISO and the Fair Market Value of the Shares subject to the underlying ISO at the time the Tandem SAR is exercised; and (c) the Tandem SAR may be exercised only when the Fair Market Value of the Shares subject to the ISO exceeds the Option exercise price of the ISO.

7.5. Payment of SAR Amount. Upon exercise of the SAR, the holder shall be entitled to receive payment of an amount determined by multiplying (a) the difference between the Fair Market Value of a share of Stock at the date of exercise over the price fixed by the Committee at the date of grant, by (b) the number of shares with respect to which the SAR is exercised. Except as otherwise provided in the Award Agreement, payment for SARs may be made in cash or Stock, or deferred cash or Stock, or in a combination thereof, at the sole discretion of the Committee; provided, however, that any cash or deferred payment hereunder shall comply with the provisions of Code Section 409A and regulations thereunder. Payment shall be made in the manner and at the time designated by the Committee in the Award Agreement.

7.6. Termination of Service. The Committee shall set forth in the applicable Award Agreement the extent to which a Participant shall have the right to exercise the SARs following termination of his or her employment, service as a Director, or consulting arrangement with the Company and/or its Subsidiaries. Such provisions shall be in the Committee's discretion, need not be uniform among all SAR Awards issued pursuant to the Plan, and may reflect distinctions based on the reasons for such termination, including, but not limited to, termination for cause or good reason, or reasons relating to the breach or threatened breach of restrictive covenants.

7.7. Non-Transferability of SARs. No SAR granted under the Plan may be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated, otherwise than by will or by the laws of descent and distribution. Further, except as otherwise provided in the Award Agreement, all SARs granted to a Participant under the Plan shall be exercisable only by such Participant during his or her lifetime. Notwithstanding the foregoing, the Committee may, in its sole discretion upon application of a Participant, permit the transfer of a SAR to a family member or family trust or partnership, or to a charitable organization, provided that no value or consideration is received by the Participant with respect to such transfer.

ARTICLE VIII
Restricted Stock and Stock Units

8.1. Grant of Restricted Stock. Subject to the terms and provisions of the Plan, Restricted Stock and/or Stock Units may be granted to one or more Participants in such number, upon such terms and provisions, and at any time and from time to time, as determined by the Committee in its sole discretion. The Company and each Participant to whom an award of Restricted Stock and/or Stock Units is granted shall execute an Award Agreement that shall specify the Period or Periods of Restriction, the number of Shares of Restricted Stock or the number of Stock Units granted, whether Stock Units shall be settled in cash or Stock, and such other provisions as the Committee shall determine.

8.2. Period of Restriction and Vesting Conditions. Subject to Article X relating to the Performance-Based Exception, the Committee may impose such conditions and/or restrictions on any Shares of Restricted Stock and/or Stock Units granted pursuant to the Plan as it may deem advisable, including, without limitation, a requirement that Participants pay a stipulated purchase price for each Share of Restricted Stock, restrictions based upon the achievement of specific performance goals as described in Section 9.1, time-based restrictions on vesting, which may or may not follow the attainment of the performance goals, sales restrictions under applicable

shareholder agreements or similar agreements, and/or restrictions under applicable Federal or state securities laws. The Period of Restriction for Restricted Stock or Stock Units shall not be less than three (3) years, during which period incremental amounts of Restricted Stock and/or Stock Units may be released from restriction in accordance with the provisions of the Award Agreement; provided, however, that the Period of Restriction for Restricted Stock or Stock Unit Awards issued to newly hired Employees in order to replace forfeited awards granted by a prior employer, or issued as a form of payment of earned Performance Awards or other incentive compensation, shall not be less than one (1) year.

8.3. Transferability. Restricted Stock and/or Stock Units granted under the Plan may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated, during the Period of Restriction, except as otherwise provided in the Award Agreement or by will or by the laws of descent and distribution. All rights with respect to Restricted Stock and/or Stock Units granted to a Participant under the Plan shall be available during his or her lifetime only to such Participant. Except as otherwise provided in the Plan or in any Award Agreement, Restricted Stock shall become freely transferable by the Participant after the last day of the applicable Period of Restriction.

8.4. Voting Rights. Except as otherwise provided in the Award Agreement, Participants holding shares of Restricted Stock granted hereunder may exercise full voting rights with respect to those shares during the Period of Restriction.

8.5. Dividends and Other Distributions. Unless otherwise designated by the Committee, Participants holding Restricted Stock granted hereunder shall be credited with regular cash dividends declared by the Company with respect to the underlying Shares during the Period of Restriction. Any other distributions with respect to the underlying Shares shall be held (without provision for interest accrual) subject to the Period of Restriction applicable to the underlying Shares. The Committee may apply any restrictions to such dividends or other distributions as it deems appropriate.

Without limiting the generality of the preceding paragraph, if the grant or vesting of Restricted Stock granted to a Named Executive Officer is designed to comply with the requirements of the Performance-Based Exception, the Committee may apply any restrictions it deems appropriate to the payment of dividends declared with respect to such Shares of Restricted Stock, such that the dividends and/or the Shares of Restricted Stock maintain eligibility for the Performance-Based Exception. In the event that any dividend constitutes a derivative security or an equity security pursuant to the rules under Section 16 of the Securities Exchange Act of 1934, such dividend shall be subject to a vesting period equal to the remaining vesting period of the Shares of Restricted Stock with respect to which the dividend is paid.

8.6. Termination of Service. The Committee shall set forth in the applicable Award Agreement the extent to which a Participant shall have the right to retain Restricted Stock following termination of his or her employment, service as a Director, or consulting arrangement with the Company and/or its Subsidiaries, during the Period of Restriction. Such provisions shall be in the sole discretion of the Committee, need not be uniform among all Restricted Stock or Stock Unit Awards issued pursuant to the Plan, and may reflect distinctions based on the reasons

for such termination, including, but not limited to, termination for cause or good reason, or reasons relating to the breach or threatened breach of restrictive covenants.

8.7. Form and Timing of Payment. Except as otherwise provided in the Award Agreement, payment for Stock Units may be made in cash or Stock, or in deferred cash or Stock, or in a combination thereof, at the sole discretion of the Committee; provided, however, that any deferred payment hereunder shall comply with the provisions of Code Section 409A and regulations thereunder. Payment shall be made in the manner and at the time designated by the Committee in the Award Agreement.

ARTICLE IX
Performance Units and Performance Shares

9.1. Grant of Performance Units or Performance Shares. Subject to the terms and provisions of the Plan, Performance Units or Performance Shares may be granted to one or more Participants in such number, upon such terms and conditions, and at any time and from time to time, as shall be determined by the Committee in its sole discretion. The Company and each Participant to whom an award of Performance Units or Performance Shares is granted shall execute an Award Agreement that shall specify the Period or Periods of Restriction, the number of Performance Units or Performance Shares granted, and such other provisions as the Committee shall determine in its sole discretion.

Subject to Article X relating to the Performance-Based Exception, the Committee may impose such other conditions and/or restrictions on any Performance Units or Performance Shares Stock granted pursuant to the Plan as it may deem advisable, including, without limitation, restrictions based upon the achievement of specific performance goals (Company-wide, Subsidiary-wide, divisional, and/or individual), time-based restrictions on vesting, which may or may not be following the attainment of the performance goals, sales restrictions under applicable shareholder agreements or similar agreements, and/or restrictions under applicable Federal or state securities laws. Performance criteria may include (among others), in the Committee's sole discretion, revenue; revenue growth; earnings (including earnings before taxes, earnings before interest and taxes or earnings before interest, taxes, depreciation and amortization); operating income; pre- or after-tax income; cash flow (before or after dividends); cash flow per share (before or after dividends); net earnings; earnings per share; return on equity; return on capital (including return on total capital or return on invested capital); cash flow return on investment; return on assets or net assets; economic value added (or an equivalent metric); share price performance; total shareholder return; improvement in or attainment of expense levels; and improvement in or attainment of working capital levels. Measurement of performance against goals may exclude, in the Committee's sole discretion, the impact of charges for restructurings, discontinued operations, extraordinary items, and other unusual or non-recurring items, and the cumulative effects of tax or accounting changes, each as defined by generally accepted accounting principles and as identified in the financial statements, notes to the financial statements, management's discussion and analysis or other SEC filings.

9.2. Value of Performance Units and Performance Shares. Each Performance Unit shall have an initial value that is established by the Committee at the time of grant. Each

Performance Share shall have an initial value determined by reference to the Fair Market Value of a Share on the grant date. The Committee shall set performance goals in its sole discretion which, depending on the extent to which they are met, will determine the number and/or value of Performance Units and/or Performance Shares that will be paid out to the Participant. The time period during which the performance goals must be met shall be called a Period of Restriction or performance period and shall be determined by the Committee in its sole discretion; provided, however, that the Period of Restriction for a Performance Unit or Performance Share Award shall not be less than one year or longer than 5 years.

9.3. Form and Timing of Payment. Except as otherwise provided in the Award Agreement, payment for Performance Unit or Performance Share Awards may be made in cash or Stock, or in deferred cash or Stock, or in a combination thereof, at the sole discretion of the Committee; provided, however, that any payment hereunder shall comply with the provisions of Code Section 409A and regulations thereunder. Payment shall be made in the manner and at the time designated by the Committee in the Award Agreement. At the time of grant or shortly thereafter, the Committee, in its sole discretion and upon such terms as the Committee shall determine consistent with Code Section 409A, may provide for a voluntary and/or mandatory deferral of all or any part of an otherwise earned Performance Unit and/or Performance Share Award.

To the extent set forth in the Award Agreement, in the sole discretion of the Committee, Participants may be entitled to receive any regular cash dividends and other distributions declared with respect to Shares which have been earned in connection with grants of Performance Units and/or Performance Shares but not yet distributed to Participants. Such dividends or other distributions shall be subject to the terms and conditions similar to those set forth in Section 8.5.

9.4. Termination of Service. The Committee shall set forth in the applicable Award Agreement the extent to which a Participant shall have the right to receive Performance Units and/or Performance Shares following termination of his or her employment, service as a Director, or consulting arrangement with the Company and/or its Subsidiaries, during the Period of Restriction. Such provisions shall be in the discretion of the Committee, need not be uniform among all Performance Units and/or Performance Shares Awards issued pursuant to the Plan, and may reflect distinctions based on the reasons for such termination, including, but not limited to, termination for cause or good reason, or reasons relating to the breach or threatened breach of restrictive covenants.

9.5. Non-Transferability. No Performance Units or Performance Shares granted under the Plan may be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated, otherwise than by will or by the laws of descent and distribution, until the termination of the applicable performance period. All rights with respect to Performance Units and Performance Shares granted to a Participant under the Plan shall be exercisable only by such Participant during his or her lifetime.

ARTICLE X
Performance Measures

10.1. Permitted Performance Measures. Unless and until the Committee proposes for shareholder vote and shareholders approve a change in the general performance measures set forth in this Article X, the attainment of which may determine the degree of payout and/or vesting with respect to Awards to Named Executive Officers that are designed to qualify for the Performance-Based Exception, the performance goals to be used for purposes of such grants shall be established by the Committee in writing and stated in terms of the attainment of specified levels of or percentage changes in any one or more of the performance measurements set forth in Section 9.1, or any individual performance objective which is measured solely in terms of quantitative targets related to the Company or the Company's business; or any combination thereof. In addition, such performance goals may be based in whole or in part upon the performance of the Company, a Subsidiary, division and/or other operational unit under one or more of such measures.

The degree of payout and/or vesting of such Awards designed to qualify for the Performance-Based Exception shall be determined based upon the written certification of the Committee as to the extent to which the performance goals and any other material terms and conditions precedent to such payment and/or vesting have been satisfied. The Committee shall have the sole discretion to adjust the determinations of the degree of attainment of the preestablished performance goals; provided, however, that the performance goals applicable to Awards which are designed to qualify for the Performance-Based Exception, and which are held by Named Executive Officers, may not be adjusted so as to increase the payment under the Award (the Committee shall retain the sole discretion to adjust such performance goals upward, or to otherwise reduce the amount of the payment and/or vesting of the Award relative to the preestablished performance goals).

In the event that applicable tax and/or securities laws change to permit Committee sole discretion to alter the governing performance measures without obtaining shareholder approval of such changes, the Committee shall have sole discretion to make such changes without obtaining shareholder approval. In addition, in the event that the Committee determines that it is advisable to grant Awards which shall not qualify for the Performance-Based Exception, the Committee may make such grants without satisfying the requirements of Code Section 162(m) and, thus, which use performance measures other than those specified above.

10.2. Compliance with Code Section 162(m). The Company intends that Options and SARs granted to Named Executive Officers and other Awards designated as Awards to Named Executive Officers shall constitute qualified "performance-based compensation" within the meaning of Code Section 162(m) and regulations thereunder, unless otherwise determined by the Committee at the time of allocation of an Award. Accordingly, the terms of Sections 2.13, 8.1, 9.1 and similar or related provisions, including the definitions of Named Executive Officer and other terms used therein, shall be interpreted in a manner consistent with Code Section 162(m) and regulations thereunder. The foregoing notwithstanding, because the Committee cannot determine with certainty whether a given Participant will be a Named Executive Officer with respect to a fiscal year that has not yet been completed, the term Named Executive Officer as used herein shall mean only a person designated by the Committee as likely to be a Named

Executive Officer with respect to a specified fiscal year. If any provision of the Plan or any Award Agreement relating to an Award that is designated as intended to comply with Code Section 162(m) does not comply or is inconsistent with the requirements of Code Section 162(m) or regulations thereunder, such provision shall be construed or deemed amended to the extent necessary to conform to such requirements, and no provision shall be deemed to confer upon the Committee or any other person sole discretion to increase the amount of compensation otherwise payable in connection with any such Award upon attainment of the applicable performance objectives.

ARTICLE XI
Beneficiary Designation

11.1. Beneficiary Designation. Each Participant under the Plan may, from time to time, name any beneficiary or beneficiaries (who may be named contingently or successively) to whom any benefit under the Plan is to be paid in case of his or her death before he or she receives any or all of such benefit. Each such designation shall revoke all prior designations by the same Participant, shall be in a form prescribed by the Company, and will be effective only when filed by the Participant in writing with the Secretary of the Company during the Participant's lifetime. In the absence of any such designation, benefits remaining unpaid at the Participant's death shall be paid to the Participant's estate.

ARTICLE XII
Rights and Obligations of Parties

12.1. No Guarantee of Employment or Service Rights. Nothing in the Plan shall interfere with or limit in any way the right of the Company to terminate any Participant's employment or consulting arrangement at any time, nor confer upon any Participant any right to continue in the employ of or consulting arrangement with the Company or any Subsidiary.

12.2. Participation. No Employee, Director or consultant shall have the right to be selected to receive an Award under the Plan, or, having been so selected, to be selected to receive a future Award.

12.3. Right of Setoff. The Company or any Subsidiary may, to the extent permitted by applicable law, deduct from and set off against any amounts the Company or Subsidiary may owe to the Participant from time to time, including amounts payable in connection with any Award, owed as wages, fringe benefits, or other compensation owed to the Participant, such amounts as may be owed by the Participant to the Company, although the Participant shall remain liable for any part of the Participant's payment obligation not satisfied through such deduction and setoff. By accepting any Award granted hereunder, the Participant agrees to any deduction or setoff under this Section 12.3.

12.4. Section 83(b) Election. No election under Section 83(b) of the Code (to include in gross income in the year of transfer the amounts specified in Code Section 83(b)) or under a similar provision of the laws of a jurisdiction outside the United States may be made, unless expressly permitted by the terms of the Award Agreement or by action of the Committee in

writing before the making of such election. In any case in which a Participant is permitted to make such an election in connection with an Award, the Participant shall notify the Company of such election within ten days of filing notice of the election with the Internal Revenue Service or other governmental authority, in addition to any filing and notification required pursuant to regulations issued under Code Section 83(b) or other applicable provision.

12.5. Disqualifying Disposition Notification. If any Participant shall make any disposition of Shares delivered pursuant to the exercise of an Incentive Stock Option under the circumstances described in Code Section 421(b) (relating to certain disqualifying dispositions), such Participant shall notify the Company of such disposition within ten days thereof.

12.6. Forfeiture of Awards. The Committee may, in its sole discretion, include in any Award Agreement the requirement that the Award be subject to additional forfeiture conditions, to which the Participant, by accepting an Award hereunder, agrees. Upon the occurrence of any forfeiture event specified by the Committee in the Award Agreement (a "Forfeiture Event"), except as otherwise provided by the Committee in the Award Agreement:

(a) The unexercised portion of any Option, whether or not vested, and any other Award not then settled will be immediately forfeited and canceled upon the occurrence of the Forfeiture Event; and

(b) The Participant will be obligated to repay to the Company upon demand, in cash, the total amount of Award Gain (as defined herein) realized by the Participant upon each exercise of an Option or SAR or settlement of an Award that occurred within the period beginning twelve (12) months prior to the earlier of the Forfeiture event or the date of the Participant's Termination of Service, and ending on the date of the Company's demand.

For purposes hereof, the term "Award Gain" shall mean (A) with respect to a given Option exercise, the product of (X) the Fair Market Value per Share at the date of such exercise (without regard to any subsequent change in the market price of shares) minus the Option exercise price times (Y) the number of Shares as to which the Option was exercised at that date, and (B) with respect to any other settlement of an Award granted to the Participant, the Fair Market Value of the cash or Shares paid or payable to the Participant less any cash or the Fair Market Value of any Shares or property (other than an Award or award that would have itself then been forfeitable hereunder and excluding any payment of tax withholding) paid by the Participant to the Company as a condition of or in connection such settlement, with actual earnings on such Award Gain through the date of payment of the Company's demand hereunder.

12.7. Restrictions on Stock Transferability. The Committee shall impose such restrictions on any shares of Stock acquired pursuant to the exercise of an Option or lapse of restrictions of any Award under the Plan as it may deem advisable, including, without limitation, restrictions under applicable Federal securities law, under the requirements of any stock exchange on which the Stock is then listed and under any blue sky or state securities laws applicable to such shares. The Committee may legend any certificates for such stock to give appropriate notice of such restrictions.

12.8. Rights of Shareholder. No Participant shall have any rights as a shareholder of the Company with respect to any Award under the Plan, except as specifically otherwise provided in the Plan or the Award Agreement.

ARTICLE XIII
Change in Control

13.1. In General. Unless otherwise specified in a Participant's Award Agreement at time of grant, except as provided in Section 13.2, or except to the extent specifically prohibited under applicable laws or by the rules and regulations of any governing governmental agencies or national securities exchanges, upon the occurrence of a Change in Control:

(a) Any and all Options and SARs granted hereunder shall become immediately exercisable, and shall remain exercisable throughout their entire then remaining term;

(b) Any Period of Restriction and other restrictions imposed on Restricted Stock or Stock Units shall lapse; and

(c) Awards of Performance Units and Performance Shares shall be converted to Restricted Stock, which shall vest over the then-remaining Period of Restriction (or upon earlier Termination of Service, death or Disability as provided in the Award Agreement). If 50% or more of the Period of Restriction has elapsed as of the date of the Change in Control, such conversion shall be based upon the value of the Performance Units and/or Performance Shares determined based upon actual performance to date; and if less than 50% of the Period of Restriction has elapsed as of the date of the Change in Control, such conversion shall be made based upon the target value of the Performance Units and/or Performance Shares.

13.2. Exceptions. Notwithstanding the foregoing provisions of Section 13.1, the Board, prior to a Change in Control, may determine that no Change in Control shall be deemed to have occurred or that some or all of the enhancements to the rights of Participants under outstanding Awards upon a Change in Control, as provided under Section 13.1 or the Award Agreement, shall not apply to specified Awards if, before or immediately upon the occurrence of the specified event that would otherwise constitute a Change in Control (the "Event"), both the Board of the Company prior to the Change in Control, and the Board of the Company (or any successor thereto) after the Change in Control reasonably conclude, in good faith, that Participants holding Awards affected by action of the Board under this Section 13.2 shall be protected by legally binding obligations of the Company because such Awards either shall remain outstanding following consummation of all transactions involved in or contemplated by such Change in Control or shall be assumed and adjusted by the surviving entity resulting from such transactions, and that changes in the terms of the Award resulting from such transactions will not materially impair the value of the Awards to the Participants or their opportunity for future appreciation in respect of such Awards.

ARTICLE XIV
Amendment, Modification, and Termination of Plan

14.1. Amendment, Modification, and Termination. The Board may amend, suspend or terminate the Plan or the Committee's authority to grant Awards under the Plan without the consent of shareholders or Participants, except as described in Sections 6.4 and 7.1; provided, however, that if shareholder approval of any amendment is required by any federal or state law or regulation or the rules of any stock exchange or automated quotation system on which the Shares may then be listed or quoted, such amendment shall be submitted to the Company's shareholders for approval not later than the earliest annual meeting for which the record date is after the date of such Board action; and provided further, that no such Board action may materially and adversely affect the rights of any Participant under any outstanding Award without the consent of such Participant. The Committee shall have no authority to waive or modify any other Award term after the Award has been granted to the extent that the waived or modified term was mandatory under the Plan.

14.2. Awards Previously Granted. The Committee may amend or modify any Award Agreement issued under the Plan or under the 1994 Omnibus Plan or 1994 Directors Plan solely to the extent provided in such Award Agreement. No termination, amendment, or modification of the Plan shall adversely affect in any material way any Award previously granted under the Plan or under the 1994 Omnibus Plan or 1994 Directors Plan, without the written consent of the Participant holding such Award.

ARTICLE XV
Tax Withholding

15.1. Tax Withholding. The Company shall have the power and the right to deduct or withhold, or require a Participant to remit to the Company, an amount sufficient to satisfy Federal, state, and local taxes, domestic or foreign, required by law or regulation to be withheld with respect to any taxable event arising as a result of the Plan.

15.2. Share Withholding. With respect to withholding required upon the exercise of Options or SARs, upon the lapse of restrictions on Restricted Stock or Stock Units, or upon any other taxable event arising as a result of Awards granted hereunder, Participants may elect, subject to the approval of the Committee, to satisfy the withholding requirement, in whole or in part, by having the Company withhold Shares having a Fair Market Value on the date the tax is to be determined equal to the minimum statutory total tax which would be imposed on the transaction. All such elections shall be irrevocable, made in writing, signed by the Participant, and shall be subject to any restrictions or limitations that the Committee, in its sole discretion, deems appropriate.

ARTICLE XVI
Indemnification

16.1. Indemnification. Each person who is or shall have been a member of the Committee or of the Board shall be indemnified and held harmless by the Company against and from any loss, cost, liability, or expense that may be imposed upon or reasonably incurred by him or her in connection with or resulting from any claim, action, suit, or proceeding to which he or she may be a party or in which he may be involved by reason of any action taken or failure to act under the Plan and against and from any and all amounts paid by him in settlement thereof, with the Company's approval, or paid by him or her in satisfaction of any judgment in any such action, suit, or proceeding against him or her, provided he or she shall give the Company an opportunity, at its own expense, to handle and defend the same before he or she undertakes to handle and defend it on his or her own behalf. The foregoing right of indemnification shall not be exclusive of any other rights of indemnification to which such persons may be entitled under the Company's Articles of Incorporation or Bylaws, as a matter of law, or otherwise, or any power that the Company may have to indemnify them or hold them harmless.

ARTICLE XVII
Requirements of Law

17.1. Requirements of Law. The granting of Awards and the issuance of Stock in connection with any Award shall be subject to all applicable laws, rules, and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

17.2. Governing Law. The Plan, and all agreements hereunder, shall be construed in accordance with and governed by the laws of the State of Arizona.

17.3. Securities Law Compliance. With respect to "insiders," transactions under the Plan are intended to comply with all applicable conditions of Rule 16b-3 or its successors under the Securities Exchange Act of 1934, as amended. To the extent any provision of the Plan or action by the Committee fails to so comply, it shall be deemed null and void, to the extent permitted by law and deemed advisable by the Committee. An "insider" includes any individual who is, on the relevant date, an officer, Director or more than 10% beneficial owner of any class of the Company's equity securities that is registered pursuant to Section 12 of the Exchange Act, all as defined under Section 16 of the Exchange Act.

17.4. Severability. In the event any provision of the Plan shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Plan, and the Plan shall be construed and enforced as if the illegal or invalid provision had not been included.

ARTICLE XVIII
Miscellaneous

18.1. Funding of Plan. Except in the case of Awards of Restricted Stock, the Plan shall be unfunded. The Company shall not be required to segregate any of its assets to assure the payment of any Award under the Plan. Neither the Participant nor any other persons shall have any interest in any fund or in any specific asset or assets of the Company or any other entity by reason of any Award, except to the extent expressly provided hereunder. The interest of each Participant and former Participant hereunder are unsecured and shall be subject to the general creditors of the Company.

18.2. Successors. All obligations of the Company under the Plan with respect to Awards granted hereunder shall be binding on any successor to the Company, whether the existence of such successor is the result of a direct or indirect merger, consolidation, purchase of all or substantially all of the business and/or assets of the Company or otherwise.

18.3. Fractional Shares. No fractional Shares shall be issued or delivered pursuant to the Plan or any Award. The Committee shall determine whether cash, other Awards or other property shall be issued or paid in lieu of such fractional Shares or whether such fractional Shares or any rights thereto shall be forfeited or otherwise eliminated.

18.4. Gender and Number; Headings. Except where otherwise indicated by the context, any masculine term used herein also shall include the feminine; the plural shall include the singular and the singular shall include the plural. Headings are included for the convenience of reference only and shall not be used in the interpretation or construction of any such provision contained in the Plan.

EXHIBIT
S-45
Admitted

COMPARISON OF GRANT COST OF EQUITY ANALYSES IN UNS GAS AND UNS ELECTRIC CASES

	UNS Gas	UNS Electric
DCF Results	9.1%-10.5% 9.9% Median	9.7%-10.5% 10.4% Median
CAPM Results	9.9%-11.7% 11.0% Median	9.8%-11.2% 10.5% Median
Risk Adjustment		0.6%
Recommendation	11.0%	11.8%
Recommended Capital Structure		
Common Equity	50.0%	48.85%
Long-Term Debt	50.0%	47.18%
Short-Term Debt		3.97%

EXHIBIT
S-46
Admitted

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S FOURTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007

STF 4.3 Please provide a description of the manner in which UNS Electric was acquired by UniSource Energy and how the acquisition was financed.

RESPONSE: The purchase price for the electric utility properties was paid in cash by UNS Electric Inc. ("UNS Electric" or "Company"). Financing for the purchase was provided through the issuance of $60 million of long-term notes at UNS Electric and through a cash equity investment made by UniSource Energy Services ("UES"), an intermediate holding company formed by UniSource Energy Corporation ("UniSource Energy"). UES obtained the cash for this equity investment from UniSource Energy. UniSource Energy used cash on hand, as well as the proceeds of a bridge loan from Union Bank of California, to make the equity investment in UES. The bridge loan was repaid in full by UniSource Energy in late 2003.

RESPONDENT: Kent Grant

WITNESS: Kent Grant

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EXHIBIT
S-48
Admitted

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S FOURTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007

STF 4.9 Please describe the manner in which UES Energy guarantees the debt of UNS Electric and UNS Gas, including how UES Energy performs the guarantees.

RESPONSE: UES is listed as the guarantor in the 2003 sale and purchase agreement for $60 million of long-term notes and in the 2006 revolving credit agreement (as amended) with a syndicate of banks. This guarantee requires UES to pay principal and interest on the $60 million of long-term notes and on any borrowings under the revolving credit facility if UNS Electric is unable to make such payments. No performance is required unless UNS Electric becomes unable to make such payments of principal and interest.

RESPONDENT: Kent Grant

WITNESS: Kent Grant

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EXHIBIT
S-49
Admitted

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S FOURTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007

STF 4.14 Please indicate if Mr. Grant believes that the rate freeze component of the 2003 settlement has negatively impacted the financial metrics, as employed by rating agencies, since 2003.

RESPONSE: Yes. As reflected in Exhibit KCG-9 attached to Mr. Kent Grant's Direct Testimony, the Company's earnings and cash flow have been negatively impacted over the period 2004 through 2006, and are expected to remain at depressed levels until rate relief is granted in this docket (assumed to occur in 2008 in this exhibit).

RESPONDENT: Kent Grant

WITNESS: Kent Grant

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S FOURTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007

EXHIBIT
S-50
Admitted
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STF 4.19 RE: "size" impact on risk of UNS Electric, as described in testimony of Mr. Grant. Please indicate if this risk factor of UNS Electric would be reduced if UNS Electric were merged into Tucson Electric.

RESPONSE: Yes.

RESPONDENT: Kent Grant

WITNESS: Kent Grant

Regulatory Research Associates An SNL Energy Company

REGULATORY FOCUS

Regulatory Study
July 3, 2007

MAJOR RATE CASE DECISIONS--JANUARY-JUNE 2007

For the first six months of 2007, the average of electric equity return authorizations by state commissions was 10.27% (18 determinations) versus 10.36% average for calendar-2006. The average gas equity return authorization for the first two quarters of 2007 was 10.34% (15 determinations), compared with the 10.43% average for calendar-2006.

After reaching a low in the late-1990's and early-2000's, the number of equity return determinations for energy companies increased somewhat beginning in 2002, and reached a ten-year high in 2005. Relatively low inflation and interest rates, technological improvements that lead to reduced costs, the use of settlements that do not specify return parameters, and a reduced number of companies due to mergers may continue to prevent the number of determinations from substantially increasing further. However, increased costs, including environmental compliance expenditures, and the need for generation and delivery system infrastructure upgrades and expansion at many companies argue for at least a modest increase in the number of cases to be filed and decided over the next several years. We also note that electric industry restructuring in many states has led to the unbundling of rates, with state commissions authorizing revenue requirement and return parameters for delivery operations only (which we footnote in our chronology table), complicating data comparability. The tables included in this study are extensions of those contained in the January 30, 2007 Special Report entitled *Major Rate Case Decisions--January 2005-December 2006--Supplemental Study*. Refer to that report for information concerning individual rate case decisions that were rendered in 2005 and 2006.

The table on page 2 shows annual average equity returns authorized since 1997, and by quarter since 2001, in major electric and gas rate decisions, followed by the number of determinations during each period. The tables on page 3 present the composite industry data for items in the chronology of this and earlier reports, summarized annually since 1997, and quarterly for the most recent six quarters. The individual electric and gas cases decided in the first six months of 2007 are listed on pages 4 and 5, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return (ROR), return on equity (ROE), and percentage of common equity in the adopted capital structure. Next we show the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base, and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

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EXHIBIT
S-51
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Average Equity Returns Authorized January 1997 - June 2007

(Return Percent - No. of Observations)

	Period	Electric Utilities	Gas Utilities
1997	Full Year	11.40 (11)	11.29 (13)
1998	Full Year	11.66 (10)	11.51 (10)
1999	Full Year	10.77 (20)	10.66 (9)
2000	Full Year	11.43 (12)	11.39 (12)
2001	1st Quarter	11.38 (2)	11.16 (4)
	2nd Quarter	10.88 (2)	10.75 (1)
	3rd Quarter	10.78 (8)	--- (0)
	4th Quarter	11.50 (6)	10.65 (2)
2001	Full Year	11.09 (18)	10.95 (7)
2002	1st Quarter	10.87 (5)	10.67 (3)
	2nd Quarter	11.41 (6)	11.64 (4)
	3rd Quarter	11.06 (4)	11.50 (3)
	4th Quarter	11.20 (7)	10.78 (11)
2002	Full Year	11.16 (22)	11.03 (21)
2003	1st Quarter	11.47 (7)	11.38 (5)
	2nd Quarter	11.16 (4)	11.36 (4)
	3rd Quarter	9.95 (5)	10.61 (5)
	4th Quarter	11.09 (6)	10.84 (11)
2003	Full Year	10.97 (22)	10.99 (25)
2004	1st Quarter	11.00 (3)	11.10 (4)
	2nd Quarter	10.54 (6)	10.25 (2)
	3rd Quarter	10.33 (2)	10.37 (8)
	4th Quarter	10.91 (8)	10.66 (6)
2004	Full Year	10.75 (19)	10.59 (20)
2005	1st Quarter	10.51 (7)	10.65 (2)
	2nd Quarter	10.05 (7)	10.54 (5)
	3rd Quarter	10.84 (4)	10.47 (5)
	4th Quarter	10.75 (11)	10.40 (14)
2005	Full Year	10.54 (29)	10.46 (26)
2006	1st Quarter	10.38 (3)	10.63 (6)
	2nd Quarter	10.69 (5)	10.50 (2)
	3rd Quarter	10.06 (7)	10.45 (3)
	4th Quarter	10.39 (10)	10.14 (5)
2006	Full Year	10.36 (25)	10.43 (16)
2007	1st Quarter	10.27 (8)	10.44 (10)
	2nd Quarter	10.27 (10)	10.15 (5)
2007	Year-To-Date	10.27 (18)	10.34 (15)

Electric Utilities--Summary Table*

	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1997	Full Year	9.16 (12)	11.40 (11)	48.79 (11)	-553.3 (33)
1998	Full Year	9.44 (9)	11.66 (10)	46.14 (8)	-429.3 (31)
1999	Full Year	8.81 (18)	10.77 (20)	45.08 (17)	-1,683.8 (30)
2000	Full Year	9.20 (12)	11.43 (12)	48.85 (12)	-291.4 (34)
2001	Full Year	8.93 (15)	11.09 (18)	47.20 (13)	14.2 (21)
2002	Full Year	8.72 (20)	11.16 (22)	46.27 (19)	-475.4 (24)
2003	Full Year	8.86 (20)	10.97 (22)	49.41 (19)	313.8 (22)
2004	Full Year	8.44 (18)	10.75 (19)	46.84 (17)	1,092.6 (30)
2005	Full Year	8.30 (26)	10.54 (29)	46.73 (27)	1,373.7 (36)
2006	1st Quarter	8.13 (3)	10.38 (3)	50.25 (3)	444.6 (9)
	2nd Quarter	8.02 (5)	10.69 (5)	45.40 (4)	130.7 (6)
	3rd Quarter	7.89 (7)	10.06 (7)	46.86 (6)	251.3 (9)
	4th Quarter	8.55 (9)	10.39 (10)	50.59 (10)	638.4 (18)
2006	Full Year	8.20 (24)	10.36 (25)	48.67 (23)	1,465.0 (42)
2007	1st Quarter	7.83 (8)	10.27 (8)	47.80 (8)	403.5 (9)
	2nd Quarter	7.92 (10)	10.27 (10)	46.03 (10)	704.2 (11)
2007	Year-To-Date	7.88 (18)	10.27 (18)	46.82 (18)	1,107.7 (20)

Gas Utilities--Summary Table*

1997	Full Year	9.13 (13)	11.29 (13)	47.78 (11)	-82.5 (21)
1998	Full Year	9.46 (10)	11.51 (10)	49.50 (10)	93.9 (20)
1999	Full Year	8.86 (9)	10.66 (9)	49.06 (9)	51.0 (14)
2000	Full Year	9.33 (13)	11.39 (12)	48.59 (12)	135.9 (20)
2001	Full Year	8.51 (6)	10.95 (7)	43.96 (5)	114.0 (11)
2002	Full Year	8.80 (20)	11.03 (21)	48.29 (18)	303.6 (26)
2003	Full Year	8.75 (22)	10.99 (25)	49.93 (22)	260.1 (30)
2004	Full Year	8.34 (21)	10.59 (20)	45.90 (20)	303.5 (31)
2005	Full Year	8.25 (29)	10.46 (26)	48.66 (24)	458.4 (34)
2006	1st Quarter	8.62 (6)	10.63 (6)	51.18 (6)	138.7 (6)
	2nd Quarter	7.98 (1)	10.50 (2)	44.38 (2)	-4.8 (2)
	3rd Quarter	8.15 (3)	10.45 (3)	47.19 (3)	38.8 (5)
	4th Quarter	7.83 (6)	10.14 (5)	44.28 (5)	271.3 (12)
2006	Full Year	8.20 (16)	10.43 (16)	47.43 (16)	444.0 (25)
2007	1st Quarter	8.36 (10)	10.44 (10)	48.33 (9)	158.4 (13)
	2nd Quarter	8.41 (4)	10.15 (5)	51.01 (5)	69.6 (6)
2007	Year-To-Date	8.37 (14)	10.34 (15)	49.29 (14)	228.0 (19)

* Number of observations in each period indicated in parentheses.

ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/5/07	Oklahoma Gas & Electric (AR)	5.36	10.00	32.33 *	12/05-YE	5.4 (B)
1/5/07	Puget Sound Energy (WA)	8.40	10.40	44.00	9/05-A	-22.8
1/11/07	Metropolitan Edison (PA)	7.52	10.10	49.00	12/06-YE	58.7 (D)
1/11/07	Pennsylvania Electric (PA)	7.92	10.10	49.00	12/06-YE	50.2 (D)
1/11/07	Wisconsin Public Service (WI)	8.63 (G)	10.90	57.46	12/07-A/P	56.7
1/12/07	Portland General Electric (OR)	8.29	10.10	50.00 (Hy)	12/07-A	20.5
1/19/07	Wisconsin Power and Light (WI)	8.68 (G)	10.80	54.13	12/07-A/P	36.2
3/21/07	Pacific Gas and Electric (CA)	---	---	---	12/07-A	192.2 (B,1)
3/22/07	Rockland Electric (NJ)	7.83	9.75	46.51	12/06-YE	6.4 (B,D)
2007	***1ST QUARTER: AVERAGES/TOTAL***	**7.83**	**10.27**	**47.80**		**403.5**
	MEDIAN	**8.11**	**10.10**	**49.00**		**---**
	OBSERVATIONS	**8**	**8**	**8**		**9**
5/15/07	Appalachian Power (VA)	7.36	10.00	41.11 *	12/05-A	24.0
5/17/07	Aquila Netwoks-MPS (MO)	8.39	10.25	48.17	12/05-YE	45.2
5/17/07	Aquila Networks-L&P (MO)	8.93	10.25	48.17	12/05-YE	13.6
5/22/07	Monongahela Pow./Potomac Ed. (WV)	8.44	10.50	46.07	12/05-YE	-6.2
5/22/07	Union Electric (MO)	7.94	10.20	52.22	6/06-YE	41.8
5/23/07	Nevada Power (NV)	9.06	10.70	47.29	6/06-YE	120.5
5/24/07	AEP Texas North (TX)	---	---	---	6/06	13.7 (B,D)
5/25/07	Public Service of New Hampshire (NH)	7.55	9.67	47.66	12/05-A	50.1 (B,D)
6/15/07	Entergy Arkansas (AR)	5.58	9.90	32.19 *	6/06-YE	-5.7
6/22/07	Appalachian Pow./Wheeling Pow. (WV)	7.67	10.50	42.88	12/06-YE	85.5 (B,2)
6/28/07	Arizona Public Service (AZ)	8.32	10.75	54.50	9/05-YE	321.7
2007	***2ND QUARTER: AVERAGES/TOTAL***	**7.92**	**10.27**	**46.03**		**704.2**
	MEDIAN	**8.13**	**10.25**	**47.48**		**---**
	OBSERVATIONS	**10**	**10**	**10**		**11**
2007	***YEAR-TO-DATE: AVERAGES/TOTAL***	**7.88**	**10.27**	**46.82**		**1107.7**
	MEDIAN	**8.12**	**10.23**	**47.92**		**---**
	OBSERVATIONS	**18**	**18**	**18**		**20**

GAS UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/5/07	Puget Sound Energy (WA)	8.40	10.40	44.00	9/05-A	29.5
1/9/07	SEMCO Energy Gas (MI)	7.75	11.00	42.94 *	---	12.6 (B)
1/11/07	Wisconsin Public Service (WI)	8.63 (G)	10.90	57.46	12/07-A/P	18.9
1/12/07	Cascade Natural Gas (WA)	8.85	---	---	---	7.1 (B)
1/19/07	Wisconsin Power and Light (WI)	8.68 (G)	10.80	54.13	12/07-A/P	-1.9
1/26/07	Fitchburg Gas & Electric (MA)	---	10.00	---	---	2.2 (B,Z)
2/8/07	PPL Gas (PA)	8.44	10.40	51.79 (Hy)	12/06-YE	8.1
3/14/07	Connecticut Natural Gas (CT)	8.60	10.10	53.60	3/06-YE	14.4 (B)
3/15/07	Union Electric (MO)	---	---	---	---	6.0 (B)
3/20/07	Delmarva Power & Light (DE)	7.73	10.25	46.90	3/06	9.0 (B,I)
3/21/07	Pacific Gas and Electric (CA)	---	---	---	12/07-A	20.5 (B,1)
3/22/07	Southern Union (MO)	8.60	10.50	36.06 (3)	12/05-YE	27.2
3/29/07	Atmos Energy (TX)	7.90	10.00	48.10	12/05-YE	4.8
2007	***1ST QUARTER: AVERAGES/TOTAL***	**8.36**	**10.44**	**48.33**		**158.4**
	MEDIAN	**8.52**	**10.40**	**48.10**		---
	OBSERVATIONS	**10**	**10**	**9**		**13**
5/16/07	Aquila (KS)	---	---	---	---	5.1 (B)
6/5/07	Cascade Natural Gas (OR)	---	10.10	45.00	---	-0.7 (B)
6/13/07	Northern States Power (ND)	8.96	10.75	51.59	12/07-A	2.2 (B)
6/18/07	Public Service of Colorado (CO)	8.67	10.25	60.17	6/06-A	32.3 (B)
6/29/07	Yankee Gas Services (CT)	8.03	10.10	50.30	6/06-A	22.1 (B)
6/29/07	Public Service Co. of New Mexico (NM)	7.96	9.53	48.00	12/05-YE	8.6
2007	***2ND QUARTER: AVERAGES/TOTAL***	**8.41**	**10.15**	**51.01**		**69.6**
	MEDIAN	**8.35**	**10.10**	**50.30**		---
	OBSERVATIONS	**4**	**5**	**5**		**6**
2007	***YEAR-TO-DATE: AVERAGES/TOTAL***	**8.37**	**10.34**	**49.29**		**228.0**
	MEDIAN	**8.52**	**10.25**	**49.20**		---
	OBSERVATIONS	**14**	**15**	**14**		**19**

FOOTNOTES

- A- Average
- B- Order followed stipulation or settlement by the parties. Decision particulars not necssarily precedent-setting or specifically adopted by the regulatory body.
- D- Applies to electric delivery only.
- E- Estimated
- G- Return on capital
- Hy- Hypothetical capital structure utilized
- I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.
- P- Partial inclusion of CWIP in rate base without AFUDC offset to income
- YE- Year-end
- Z- Rate change implemented in multiple steps.
- * Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) Rate increase effective retroactive to 1/1/07.
(2) Returns implicit in settlement.
(3) Parent company capital structure utilized.

Dennis Sperduto

EXHIBIT
S-52
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

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 AND REQUEST FOR APPROVAL OF RELATED FINANCING	DOCKET NO. E-04204A-06-0783

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JUNE 28, 2007

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I. INTRODUCTION

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

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. Please summarize your education background and professional experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. In connection with this, I have previously filed testimony and/or testified in about 400 utility proceedings before some 40 regulatory agencies in the United States and Canada. Schedule 1 provides a more complete description of my education and relevant work experience.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes, I have testified in a number of prior Arizona Corporation Commission ("Commission") proceedings, including the recent electric rate case involving Arizona Public Service Company (Docket No. E-01345A-05-0816) and the recent gas rate case involving UNS Gas, Inc. (Docket No. G-01345A-05-0463). Those testimonies were provided on behalf of the Commission Staff.

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

A. I have been retained by the Commission Staff to evaluate the cost of capital aspects of the current filing of UNS Electric, Inc. ("UNS Electric"). I have performed independent

studies and am making recommendations of the current cost of capital for UNS Electric. In addition, because UNS Electric is a subsidiary of UniSource Energy Corporation ("UniSource Energy"), I also have evaluated this entity in my analyses.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, I have prepared one exhibit, identified as Schedule 1 through Schedule 14. This exhibit was prepared either by me or under my direction. The information contained in this exhibit is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. What are your recommendations in this proceeding?

A. My overall cost of capital recommendations for UNS Electric are:

	Percent	Cost	Return
Short-Term Debt	3.96%	6.36%	0.25%
Long-Term Debt	47.21%	8.16%	3.85%
Common Equity	48.83%	9.5-10.5%	4.64-5.13%
Total	100.00%		8.74-9.23%
			8.99% mid-point

UNS Electric's application requests a return on common equity of 11.8 percent and overall rate of return of 9.89 percent.

Q. Please summarize your cost of capital analyses and related conclusions for UNS Electric.

A. This proceeding is concerned with UNS Electric's regulated electric distribution utility operations in Arizona. My analyses are concerned with the Company's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. UNS Electric's proposed capital structure is its capital structure as of June 30, 2007. I use the actual test period capital structure of UNS Electric as of June 30, 2006 in my cost of capital analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rates of long-term debt and short-term debt. I have used the test period 8.16 percent cost rate for long-term debt and 6.36 percent cost of short-term debt contained in UNS Electric's application.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for UNS Electric. Each of these methodologies is applied to two groups: one of proxy combination electric and gas utilities, and the proxy group used by UNS Electric Witness Grant. These three methodologies and my findings are:

Methodology	Range	
Discounted Cash Flow	9.5-10.5%	(10.0% mid-point)
Capital Asset Pricing Model	10.0-10.5%	(10.25% mid-point)
Comparable Earnings	10.0%	

Based upon these findings, I conclude that the cost of common equity for UNS Electric is within a range of 9.5 percent to 10.5 percent (10.0 percent mid-point), which reflects each of the model results.

Using the results from these three steps, I have calculated a weighted cost of capital (overall rate of return) range of 8.74 percent to 9.23 percent (8.99 percent mid-point, which incorporates a cost of common equity of 10.0 percent). My specific cost of capital recommendation for UNS Electric is 8.99 percent.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. What are the primary economic and legal principles that establish the standards for determining a fair rate of return for a regulated utility?

A. Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service"

ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. The revenue impact of the cost of capital is thus derived by multiplying the rate base by the rate of return and allowing a factor for income taxes.

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an ex post (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an ex ante (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably. I have equated the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These

concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two United States Supreme Court decisions are universally cited as providing the standards for a fair rate of return. The first is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of fair and enlightened judgment**, having regard to all relevant facts. 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. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. **[Emphasis added.]**

It is my understanding that the Bluefield decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a **balancing** of the **investor** and **consumer interests** . . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the **return** to the equity **owner** should be **commensurate** with **returns** on **investments** in **other enterprises having corresponding risks**. That return, moreover, should be sufficient to assure confidence in the **financial integrity** of the enterprise, so as to **maintain its credit** and to **attract capital**. **[Emphasis added.]**

The Hope case is also frequently credited with establishing the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

The three economic and financial parameters in the Bluefield and Hope decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely, that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. In *Simms v. Round Valley Light & Power Company*,[1] the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

[1] 294 P.2d 378 (1956).

> "In the Hope case the Court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was controlling and that it was unimportant to 'determine the various permissible ways in which any rate base on which the return is computed might be arrived at."

My testimony does not advocate that the Commission ignore the *Simms* holding in this regard, or the fair value of UNS Electric' property, which it is required to consider under Article 15, Section of the Arizona Constitution. Rather, I find the *Hope* and *Bluefield* decisions to be helpful in their discussion of comparable earnings, financial integrity and capital attraction. I note that UNS Electric Witness Pignatelli also cites the Hope and Bluefield cases as "guidelines" for evaluating the cost of capital for the Company.

Q. How can these parameters be employed to estimate the cost of capital for a utility?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the component of the capital structure that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

Q. Which methods have you employed in your analyses of the cost of common equity in this proceeding?

A. I have utilized three methodologies to determine UNS Electric's cost of common equity: the DCF, CAPM, and CE methods. Each of these methodologies will be described in more detail in my testimony that follows.

IV. GENERAL ECONOMIC CONDITIONS

Q. Why are economic and financial conditions important in determining the costs of capital?

A. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the costs of capital: the level of economic activity (i.e., growth rate of the economy), the stage of the business cycle (i.e., recession, expansion, or transition), and the level of inflation. My understanding is that use of the factors is consistent with the Supreme Court's Bluefield decision, which noted that "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."

Q. What indicators of economic and financial activity have you evaluated in your analyses?

A. I have examined several sets of economic statistics for the period 1975 to present. I chose this period because it permits the evaluation of economic conditions over three full business cycles plus the current cycle to date, and thus makes it possible to assess changes in long-term trends. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences and thus permits a comparison of structural (or long-term) trends.

Q. Please describe the timeframe of the three prior business cycles and the most current cycle.

A. The three prior complete cycles and current cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
Current	Dec. 2001-Present	

Q. Do you have any general observations concerning the changing trends in economic conditions and their impact on costs over this broad period?

A. Yes, I do. As I will describe below, the U.S. economy has enjoyed general prosperity and stability over the period since the early 1980s. This period has been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs. The current business cycle began in late 2001, following a somewhat modest recession in 2001. During the recession and early in the succeeding expansion, the Federal Reserve lowered interest rates (i.e., Fed Funds rate) 11 times in 2001 and twice in 2003 in an effort to stimulate the economy.

Q. Please describe recent and current economic and financial conditions and their impact on the costs of capital.

A. Schedule 2 shows several sets of economic data. Page 1 contains general macroeconomic statistics while Pages 2 and 3 contain financial market statistics. Page 1 of Schedule 2 shows that the U.S. economy is currently in the fifth year of an economic expansion. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product, industrial production, and the unemployment rate. This current expansion has generally been characterized as slower growth, in comparison to prior expansions. This has resulted in lower inflationary pressures and interest rates.

The rate of inflation is also shown on Page 1 of Schedule 2. As is reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business cycle. The 2.5 percent rate of inflation in 2006 was similar to the levels since 2000, but was well below the levels of the past thirty years.

Q. What have been the trends in interest rates?

A. Page 2 of Schedule 2 shows several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates then fell substantially in conjunction with inflation rates throughout the remainder of the 1980s and throughout the 1990s. Interest rates declined even further from 2000-2004 and generally recorded their lowest levels since the 1960s.

This low level of interest rates, in conjunction with the recent strength of the U.S. economy, may create an expectation that any near-term movement of interest rates will be

upward. In fact, the Federal Reserve has, since the middle of 2004, increased short-term interest rates on 17 occasions, although each time by only 0.25 percent, in an attempt to insure that any perceived inflationary expectations will not stifle continued economic growth. Nevertheless, the economic recovery to date has not resulted in a pronounced increase in long-term rates. Further, the current level of Fed Funds is about the same as the level in existence when the series of reductions began in 2000. Even if long-term rates were to increase moderately, they would still remain well below historical levels.

Q. What have been the trends in common share prices?

A. Page 3 of Schedule 2 shows several series of common stock prices and ratios. These indicate that share prices were basically stagnant during the high inflation/interest rate environment of the late 1970s and early 1980s. On the other hand, the 1983-1991 business cycle and the most recent cycle have witnessed a significant upward trend in stock prices. During the initial years of the current expansion, however, stock prices were volatile and declined substantially from their highs reached in 1999 and early 2000. Share prices have increased somewhat since 2003 and currently stand at near record high levels.

Q. What conclusions do you draw from this discussion of economic and financial conditions?

A. It is apparent that capital costs are currently low in comparison to the levels that have prevailed over the past three decades. In addition, even a moderate increase in interest rates, as well as other capital costs, would still result in capital costs that are low by historic standards. Therefore, it can reasonably be expected that cost of equity models currently produce returns that are lower than was the case in prior years.

V. UNS ELECTRIC' OPERATIONS AND RISKS

Q. Please summarize UNS Electric and its operations.

A. UNS Electric is a public utility that provides electric distribution services to some 93,000 customers in Arizona. UNS Electric was formerly the Arizona electric distribution operations of Citizens Communications Company, prior to its 2003 acquisition by UniSource Energy. When UniSource Energy acquired the Arizona electric and gas assets from Citizens, it formed two operating companies - UNS Electric and UNS Gas.

Q. Please describe Unisource Energy.

A. UniSource Energy is a holding company, whose principal subsidiary is Tucson Electric Power Company ("TEP"), a generation and distribution company that is the second-largest investor-owned utility in Arizona. UniSource Energy also owns UniSource Energy Services ("UES"), which contains UNS Electric and UNS Gas, both of which are distribution companies. It previously owned Millennium Energy Holdings, the parent company of UniSource Energy's unregulated energy business whose principal subsidiary was Global Solar. UniSource Energy presently operates through three primary business segments – TEP, UNS Electric and UNS Gas.

Q. What have been the business segment ratios of Unisource Energy in recent years?

A. This is shown on Schedule 3. As this indicates, as of 2006, UNS Electric accounted for about 12 percent of the revenues of UniSource Energy and about 6 percent of total assets.

Q. What are the current bond ratings of Unisource Energy and TEP?

A. The current ratings of UniSource Energy and TEP are:

	Standard & Poor's	Moody's	Fitch
UniSource Energy Credit Ratings			
Senior Secured Debt	NR	Ba1	NR
Issuer Rating	NR	Ba1	N/A
Tucson Electric Power Credit Ratings			
Senior Secured Debt	BBB-	Baa2	BBB-
Senior Unsecured Debt	B+	Baa3	BB+
Issuer Rating	BB	Baa3	BB

Source: UniSource Energy Web Site.

UNS Electric does not have its own security ratings, and its single debt issue was privately placed in 2003 at the time of the acquisition. The debt of UNS Electric is guaranteed by UES. As such, the debt of UNS Electric is related to the overall credit strength of UniSource Energy.

Q. Did the acquisition of the assets current comprising UNS Electric have any impact on the security ratings of Unisource Energy or TEP?

A. No, it did not. Standard & Poor's, for example, made the following comments in an August 12, 2003 CreditWatch report on TEP:

> Standard & Poor's Ratings Services said today it affirmed its ratings on Tucson Electric Power Co. ('BB' corporate credit rating) and removed them from CreditWatch with negative implications. They were placed on CreditWatch Nov. 8, 2002, reflecting parent UniSource Energy Corp.'s announcement of an agreement to **purchase** the **Arizona electric** and gas **transmission and distribution assets** from Citizens Communications Co. The outlook is stable.
>
> The Aug. 11, 2003, acquisition of **these relatively low-risk, widely scattered regulated assets** for $220 million, **well below the book value** of about $425 million, **bolsters the consolidated business profile** of the UniSource Energy family of companies, and does so with a financing package that **marginally improves the overall financial condition of UniSource Energy**. These assets are subject to regulation by the Arizona Corporation Commission (ACC), as is Tucson Electric, and are structured

> as a wholly owned subsidiary of UniSource Energy called UniSource Energy Services.
>
> The addition of about 77,000 electric customers and 126,000 gas customers represents an increase of about 40% to Tucson Electric's customer base. The acquisition has received strong regulatory support, mainly because rate increases will be limited to only about one-half of what they would have been in the absence of the purchase, as well as because of operational challenges faced by prior management. **[Emphasis added]**

Q. Are you aware that UNS Electric is requesting the inclusion of construction work in process as part of its rate filing?

A. Yes, I am. It is my understanding that UNS Electric is requesting some $10.8 million of Construction Work In Progress ("CWIP") in its request, which results in about $2.1 million of annual revenues to the Company. UNS Electric witness Grant cites the inclusion of CWIP as necessary for the Company to attract capital.

Q. Do you agree that it is necessary for UNS Electric to have CWIP treatment in order for it to attract capital?

A. No, I do not. It has been my general experience that CWIP treatment is generally regarded as a ratemaking practice to be used in situations where a utility has a very large construction program and the company requires the cash treatment in order to manage its construction program and related financing. As such, CWIP is not the norm.

In the case of UNS Electric, I do not believe that it is necessary to provide CWIP treatment in order for this Company to attract capital. As I indicated above, the rating agencies describe the operations of UNS Electric as low risk. It is further apparent that UNS Electric receives its financing based on the credit quality of UniSource Energy and/or UES, not based on the situation of the Company itself. In summary, I do not

believe it is necessary for UNS Electric to receive CWIP treatment in order for it to attract capital.

VI. CAPITAL STRUCTURE AND COST OF DEBT

Q. What is the importance of determining a proper capital structure in a regulatory framework?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the pool of dollars represented by the capital structure finance the rate base.

The common equity ratio (i.e., the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and, (3) causes the most controversy since its cost cannot be precisely determined.

Q. How is UNS Electric financed?

A. UNS Electric is a subsidiary of UES, which in turn is a subsidiary of UniSource Energy. UNS Electric has one series of long-term notes outstanding, which is guaranteed by UES.

Q. How have you evaluated the capital structure of UNS Electric and Unisource Energy?

A. I have first examined the recent capital structure ratios of UNS Electric and UniSource Energy.

UNS Electric' capital structure did not exist until 2003, when UniSource Energy created a subsidiary from the electric distribution assets in Arizona, as acquired from Citizens Communications. As is shown on Page 1 of Schedule 4, the common equity ratios of UNS Electric have been as follows:

	Including S-T Debt	Excluding S-T Debt
2003	37.6%	37.9%
2004	40.3%	40.5%
2005	45.2%	45.4%
2006	45.0%	45.1%

This indicates a rising level of common equity over this period.

Q. What are the capital structure ratios of Unisource Energy?

A. These are shown on Page 2 of Schedule 4. These common equity ratios of UniSource Energy, on a consolidated basis, are summarized below:

	Including S-T Debt	Excluding S-T Debt
2002	28.8%	28.8%
2003	30.2%	30.2%
2004	31.6%	31.6%
2005	33.6%	33.7%
2006	34.9%	35.8%

These common equity ratios are substantially less than those of UNS Electric.

Q. How do the capital structures of UNS Electric compare to the other utility subsidiaries of Unisource Energy?

A. This is shown on Page 3 of Schedule 4. As this indicates, UNS Electric and UNS Gas have higher common equity ratios than TEP and UniSource Energy.

Q. How do these capital structures compare to those of investor-owned electric and combination gas/electric utilities?

A. Schedule 5 shows the common equity ratios (including short-term debt in capitalization) for the two groups of electric utilities covered by AUS Utility Reports. These are:

Year	Electric	Combination Gas And Electric
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%
2006	45%	44%

These common equity ratios are generally similar to those of UNS Electric in 2006.

Q. What capital structure ratios has UNS Electric requested in this proceeding?

A. The Company requests use of its June 30, 2007 capital structure ratios. This contains a requested common equity ratio of 48.85 percent.

Q. What capital structure do you propose to use in this proceeding?

A. I propose use of the actual capital structure ratios of UNS Electric as of June 30, 2006. This capital structure reflects the test period per books ratios of the Company. This is very similar to the June 30, 2007 capital structure proposed by UNS Electric.

Q. What is the cost rate of long-term debt in the company's application?

A. The Company's filing cites, as of June 30, 2006, a cost of long-term debt of 8.16 percent and a cost of short-term debt of 6.36 percent. I use these rates in my cost of capital analyses.

Q. Can the cost of common equity be determined with the same degree of precision as the cost of debt?

A. No. The cost rate of debt is largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. There are, however, several models which can be employed to estimate the cost of common equity. Three of the primary methods - DCF, CAPM, and CE - are developed in the following sections of my testimony.

VII. SELECTION OF PROXY GROUPS

Q. How have you estimated the cost of common equity for UNS Electric?

A. UNS Electric is not a publicly-traded company. Consequently, it is not possible to directly apply cost of equity models to this entity. Its ultimate parent company, UniSource Energy, is publicly-traded. As a result, it is possible to conduct direct analyses of its cost of common equity, although this company's recent financial situation and diversified nature make its results of limited value. Consequently, it is necessary to analyze groups of

comparison or "proxy" companies as a substitute for UNS Electric to determine its cost of common equity.

I have examined two such groups for comparison to UNS Electric. The first group of proxy companies I examined is a group of nine electric and combination gas electric companies, similar to UniSource Energy, selected based on the criteria shown on my Schedule 6. Second is the group of eight combination gas and electric utilities used by UNS Electric witness Grant in his cost of capital analyses.

VIII. DISCOUNTED CASH FLOW ANALYSIS

Q. What is the theory and methodological basis of the discounted cash flow model?

A. The discounted cash flow model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework cost of capital is derived by the following formula:

$$K = \frac{D}{P} + g$$

where: K = discount rate (cost of capital)
P = current price
D = current dividend rate
G = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how you have employed the DCF model.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. How did you derive the dividend yield component of the DCF equation?

A. There are several methods that can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed; i.e., current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is a dividend growth variant, which is expressed as follows:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (March-May 2007). The D_0 is the current annualized dividend rate for each proxy company.

Q. How have you estimated the dividend growth component of the DCF equation?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock.

A wide array of indicators exist for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2002-2006 (5-year average) earnings retention, or fundamental growth (per Value Line);
2. 5-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS) (per Value Line);
3. 2007, 2008, and 2010-2012 projections of earnings retention growth (per Value Line);
4. 2004-2006 to 2010-2012 projections of EPS, DPS, and BVPS (per Value Line); and,
5. 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. Please describe your initial DCF calculations.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies. Page 4 shows the "raw" DCF calculations, which are presented on several bases: mean, median, and high values. These results can be summarized as follows:

	Mean	Median	High[2]
Comparison Group	8.5%	8.6%	11.7%
Grant Group	8.3%	8.3%	11.5%

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected cost of capital for the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors.

The DCF results in Schedule 7 indicate average (mean and median) DCF cost rates of about 8.5 percent. The highest DCF rates (i.e., using the single highest growth rates only) are about 11½ percent. This indicates a broad range of DCF results of 8.5 percent to 11.5 percent.

[2] Using only the highest growth rate.

Q. What do you conclude from your DCF analyses?

A. Based upon my analyses, I believe a range of 9.5 percent to 10.5 percent represents the current DCF cost of equity for the proxy groups. This is approximated by the middle of the DCF calculations for the groups examined in the previous analysis. I recommend a 9.5 percent to 10.5 percent (10.0 percent mid-point) for UNS Electric.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. Please describe the theory and methodological basis of the capital asset pricing model.

A. The Capital Asset Pricing Model ("CAPM") is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory (MPT), which studies the relationships among risk, diversification, and expected returns.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where:
K = cost of equity
R_f = risk free rate
R_m = return on market
β = beta
R_m-R_f = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the

simple risk premium method does not, but rather the simple risk premium method assumes the same cost of equity for all companies exhibiting similar bond ratings.

Q. What groups of companies have you utilized to perform your CAPM analyses?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

Q. What rate did you use for the risk-free rate?

A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three month average yield (March-May 2007) for 20-year U.S. Treasury bonds. Over this three month period, these bonds had an average yield of 4.91 percent.

Q. What is beta and what betas did you employ in your CAPM

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas of less than 1 are considered less risky than the market, whereas betas greater than 1 are more risky. Utility stocks traditionally have had betas below 1. I utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. How did you estimate the market risk premium component?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the return on equity for the S&P 500 group for the period 1978-2005 (all available years reported by S&P). The average return on equity for the S&P 500 group over the 1978-2005 period is 14.09 percent. This Schedule also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual differentials (i.e., risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that this version of the risk premium is about 6.2 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for the long-term government bonds, as tabulated by Ibbotson Associates, using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2005 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	12.3%	5.8%	6.5%
Geometric	10.4%	5.4%	5.0%

I conclude from this that the expected risk premium is about 5.9 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 9 shows my CAPM calculations using the risk premium. The results are:

	Mean	Median
Comparison Group	10.6%	10.5%
Grant Group	10.2%	9.9%

Q. What is your conclusion concerning the CAPM cost of equity?

A. The CAPM results collectively indicate a cost of about 10 percent to 10.5 percent for the two groups of comparison utilities.

X. COMPARABLE EARNINGS ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, because the CE method translates into practice the competitive principle upon which regulation is based.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's original book value (reflected in the book common equity in its balance sheet) to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the

utility. This technique is thus consistent with the rate base methodology used to set utility rates.

Q. How have you employed the CE methodology in your analysis of UNS Electric' common equity cost?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (i.e., 100%) reflect a situation where a company is able to attract new equity capital without dilution of book value. As a result, maintenance of a stock price above book value is one measure of the fairness of a utility's authorized cost of equity.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my comparable earnings analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my comparable earnings analysis uses prospective returns and thus is not backward looking.

Q. What time periods have you examined in your CE analysis?

A. My CE analysis considers the experienced equity returns of the proxy groups of utilities for the period 1992-2006 (i.e., last fifteen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is

important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two periods: 2002-2006 (the last five years - the average length of a business cycle) and 1992-2001 (the most recent complete business cycle).

Q. Please describe your CE analysis.

A. Schedules 10 and 11 contain summaries of experienced returns on equity for several groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the earned returns on average common equity and market-to-book ratios for the two groups of proxy utilities. These can be summarized as follows:

	Historic		Prospective
Group	ROE	M/B	ROE
Comaprison Group	9.0-10.2%	153-154%	10.6-10.7%
Grant Group	9.5-10.6%	148-153%	9.5-10.3%

These results indicate that historic returns of 9.0-10.6 percent have been adequate to produce market-to-book ratios of 148-154 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2007, 2008, and 2010-2012 are within a range of 9.5 percent to 10.7 percent for the utility groups. These relate to 2006 market-to-book ratios of 151 percent or higher.

Q. Have you also reviewed earnings of unregulated firms?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well recognized

group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 11 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past fourteen years. As this Schedule indicates, over the two periods this group's average earned returns ranged from 12.2 to 14.7 percent with market-to-book ratios ranging from 299 to 341 percent.

Q. How can the above information be used to estimate the cost of equity for UNS Electric?

A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for proxy utilities, however, it is necessary to compare the risk levels of the utility industries with those of the competitive sector. I have done this in Schedule 12, which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is slightly more risky than the utility proxy groups.

Q. What return on equity is indicated by the CE analysis?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for the proxy utilities is no more than 10 percent. Recent returns of 9.0-10.6 percent have resulting in market-to-book ratios of 148 and greater. Prospective returns of 9.5 to 10.7 percent have been accompanied by market-to-book ratios of over 151 percent. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 10 percent or less should thus result in a market-to-book ratio of at least 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that

historic and prospective returns of 10 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three cost of equity analyses.

A. My three methodologies produce the following:

Discounted Cash Flow	9.5-10.5% (10.0% mid-point)
Capital Asset Pricing Model	10.0-10.5% (10.25% mid-point)
Comparable Earnings	10.0%

My overall conclusion from these results is an overall range of 9.5 percent to 10.5 percent, which focuses on the respective ranges of my individual model findings. Focusing on the respective mid-points, the range is 10 percent to 10.25 percent. I conclude that the cost of equity rate for UNS Electric is in the range from 9.5 percent to 10.5 percent (mid-point 10.0 percent).

XII. TOTAL COST OF CAPITAL

Q. What is the total cost of capital for UNS Electric?

A. Schedule 13 reflects the total cost of capital for the Company using the June 30, 2006 capital structure and costs of long-term and short term debt, and my common equity cost recommendations. The resulting total cost of capital is a range of 8.74 percent to 9.23 percent, with a mid-point of 8.99 percent. I recommend that this 8.99 total cost of capital be established for UNS Electric.

Q. Does your cost of capital recommendation provide the company with a sufficient level of earnings to maintain its financial integrity?

A. Yes, it does. Schedule 14 shows the pre-tax coverage that would result if UNS Electric earned the mid-point of my cost of capital recommendation. As the results indicate, the mid-point of my recommended range would produce a coverage level within the benchmark range for an A rated utility.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. Have you reviewed the testimony and cost of capital recommendation of UNS Electric witness Kentton C. Grant?

A. Yes, I have. Mr. Grant is recommending the following cost of capital for UNS Electric:

Capital Item	Percent	Cost	Weighted Cost
Short-term Debt	3.97%	6.36%	0.25%
Long-term Debt	47.18%	8.22%	3.88%
Common Equity	48.85%	11.80%	5.76%
Total	100.0%		9.89%

Mr. Grant's 11.8 percent cost of common equity recommendation is derived as follows:

	Range	Median
DCF	9.7-10.5%	10.4%
CAPM	9.8-11.2%	10.5%

Q. Do you have any comments concerning Mr. Grant's DCF analysis and recommendations?

A. I note that Mr. Grant's 9.7-10.5 percent DCF conclusions do not vary significantly from my DCF conclusions of 9.0-10.5 percent. As a result, I have no further comments on his DCF analyses and conclusions at this time.

Q. What are your comments concerning Mr. Grant's CAPM analysis and conclusions?

A. Mr. Grant's CAPM analysis takes the following form:

Risk-free rate	=	4.84%	=	September, 2006 20-yr. T bonds Yield
Risk Premium	=	7.1%	=	Ibbotson risk premium
Beta	=		=	Value Line

My primary disagreement is with Mr. Grant's risk premium input.

My disagreements with Mr. Grant's risk premium is his exclusive reliance on the 1926-2005 arithmetic average differences between large company stocks (i.e., S&P 500) and long-term Treasury bonds. As I indicated earlier in my testimony, it is preferable to use multiple sources of risk premium measures, as I have done. Mr. Grant's 7.1 percent risk premium used only arithmetic returns, and ignores geometric (compound) returns in deriving the risk premium component of the CAPM. This is not proper. What is important is not what Mr. Grant and I believe, but what investors rely upon in making investment decisions. It is apparent that investors have access to both types of returns, and correspondingly use both types of returns, when they make investment decisions.

In fact, it is noteworthy that mutual fund investors regulatory receive reports on their own funds, as well as prospective funds they are considering investing in, that show only geometric returns. Based on this, I find it difficult to accept Mr. Grant's position that only arithmetic returns are considered by investors, and, thus, only arithmetic returns are appropriate in a CAPM context.

Q. Does Mr. Grant use value line information in his cost of capital analyses?

A. Yes, he does.

Q. Do the value line reports cited in his testimony show historic growth rates for the electric utilities?

A. Yes, they do.

Q. Do these value line reports show historic returns on an arithmetic basis?

A. No, they do not.

Q. Do the value line reports show historic returns on a geometric, or compound growth rate basis?

A. Yes, they do. As a result, any investor reviewing Value Line, as Mr. Grant does, would be using geometric growth rates, not arithmetic growth rates.

Q. Is it you position that only geometric growth rates be used?

A. No. I believe that both arithmetic and geometric growth rates should be used. This is the case since investors have access to both and presumably use both.

Q. Mr. Grant also makes an adjustment for the size of UNS Electric, is this proper?

A. No, it is not. UNS Electric does not raise its own equity capital (as it comes from UniSource Energy) and its debt is guaranteed by UES. As a result, it is these entities that are evaluated by investors and it is the size of these entities that investors consider. I note in this regard, that UniSource Energy as some $1.4 billion market value of equity and Value Line describes this Company as a "Mid Cap" stock.

Q. Mr. Grant also cites the growth of UNS Electric as a risk indicator. Do you agree with this?

A. No, I do not. My earlier testimony cites a S&P analysis of UniSource Energy that describes the UNS Electric and UNS Energy components as "low-risk."

Q. Mr. Grant also claims, on page 23, that his 11.8 percent recommendation is "reasonable" in comparison to the authorized returns on equity for other electric utilities. Do you have any response to this?

A. Yes, I do. The source Mr. Grant is quoting – Regulatory Research Associates – compiles the authorized returns on equity for utilities, including electric utilities. I note the following trend in authorized returns on equity over the past several years:

2000	11.43%
2001	11.09%
2002	11.16%
2003	10.99%
2004	10.75%
2005	10.54%
2006	10.36%

It is apparent from this that average authorized returns on equity have not been as high as 11.8 percent since at least 2000 and they have not been as high as 11.0 percent since 2002. It is also apparent that the average level of authorized return on equity has declined in each year since 2002 a period of four years. It is thus apparent that Mr. Grant's 11.8 percent requested return on equity ignores both the trend and level of authorized returns.

Q. Do you have any comments on Mr. Grant's recommendation for UNS Electric?

A. Yes, I do. Mr. Grant's DCF and CAPM findings can be summarized as follows:

	DCF	CAPM	Recommendation
Low End	9.7%	9.8%	9.7%
High End	10.5%	11.2%	11.2%
Mid-Point	10.1%	10.5%	

It is apparent that, had Mr. Grant focused on the respective mid-points of his DCF and CAPM ranges, his recommendation should have been a range of 10.1 percent to 10.8 percent, which is similar to my recommended range. However, his recommendation instead focuses on the top end of the CAPM range, or 11.2 percent, which is the CAPM result for a single company. Further, as is evident from Mr. Grant's Exhibit KCG-5, the average CAPM result excluding Cleco Corp. (whose CAPM result is 13.7 percent, or 250 basis points higher than his next highest CAPM rate – 11.2 percent) is 10.5 percent. This 10.5 percent is also the median CAPM result excluding Cleco. In addition, had Mr. Grant more appropriately focused on the median results of his DCF and CAPM models, his conclusions would have been 10.35 percent to 10.5 percent and had he focused on the average results his conclusions would have been 10.2 percent to 10.5 percent. Again, his 11.2 percent upper end represents the CAPM result of a single company, which ultimately drives his 9.7 percent to 11.2 percent recommendation.

In addition, Mr. Grant compounds his over-statement of the cost of equity for UNS Electric by adding sixty basis points to his 9.7 percent to 11.2 percent range to reflect the "decidedly riskier" nature of UNS Electric's operations relative to the comparable group. This sixty basis point adjustment is based on the differential in yields between Triple-B utility bonds and Double-B utility bonds, which implicitly and incorrectly assumes that UNS Electric is a non-investment grade company.

Finally, Mr. Grant's 11.8 percent recommendation for UNS Electric is based on the upper end of his modified recommended range (i.e., 10.3 percent to 11.8 percent), which in essence means that his recommendation is based on the CAPM results for a single company, adjusted upward by sixty basis points based on an erroneous assumption that UNS Electric is a non-investment grade company.

XIV. UNS ELECTRIC PROPOSAL TO APPLY COST OF CAPITAL TO FAIR VALUE RATE BASE

Q. What is your understanding of UNS Gas' proposal to apply the company's cost of captial to a fair value rate base?

A. According to Schedule A-1, UNS Electric is proposing that the total cost of capital for the Company be applied to the "fair value" of the Company's rate base. This request is apparently being made in response to a recent Arizona Court of Appeals decision regarding Chaparral City Water Company. I note, on the other hand, that no UNS Electric witness appears to be endorsing this ratemaking treatment. In particular, Mr. Pignatelli and Mr. Grant, the two witnesses who address the Company's cost of capital, do not cite this.

Q. Have you reviewed this decision and do you have any comments on your understanding of its implications for this case?

A. Yes, I do. My "non-legal understanding" of this decision is that the Commission must consider the fair value of a utility's assets in setting rates. However, I do not agree with UNS Electric that this implies that the Company's cost of capital must be applied to the fair value of the rate base.

My "non-legal understanding" of the Court decision indicates that the Court agreed with the Commission that "the cost of capital analysis 'is geared to concepts of original cost measures of rate base, not fair value measures of rate base' and thus was appropriately applied here to the OCRB." The decision went on to state "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

Q. Do you have any observations based upon your own experience in cost of capital determination, as to whether the cost of capital is consistent with a fair value rate base?

A. Yes, I do. It is my personal experience, based upon over 35 years of providing cost of capital testimony, that the entire concept of cost of capital is designed to apply to an original cost rate base. This is the case since the cost of capital is derived from the liabilities/owners' equity side of a utility's balance sheet using the book values of the capital structure components. The cost of capital, once determined, is then applied to (i.e., multiplied by) the rate base, which is derived from the asset side of the balance sheet. From a financial, as well as regulatory, perspective, the rationale for this relationship is that the rate base is financed by the capitalization. Under this relationship, a provision is provided for investors (both lenders and owners) to receive a return on their invested capital. Such a relationship is meaningful as long as the cost of capital is applied to the original cost (i.e., book value) rate base, because there is a matching of rate base and capitalization.

When the concept of fair value rate base is incorporated, however, this link between rate base and capital structure is broken. The "excess" of fair value rate base over original cost rate base is not financed with investor-supplied funds and, indeed, the excess is not financed at all. As a result, the cost of capital cannot be applied to the fair value rate base since there is no financial link between the two concepts.

Q. Why is it important that there be a link between the concepts of rate case and cost of capital?

A. This link is important since financial theory, as well as regulatory precedent, indicates that investors should be provided an opportunity to earn a return on the capital they provided

to the utility. Since the capital finances the rate base (in an original cost world) the link between cost of capital and rate base satisfies this financial and regulatory objective.

Q. Based on your experience as a cost of capital witness over the past 35 years, do you have a proposed solution for the commission to account for the use of a fair value rate base in setting rates for UNS Electric?

A. Yes, I do. Since the differential between fair value rate base and original cost rate base is not financed with investor-supplied funds, it is logical and appropriate to assume that this excess has no cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the excess of fair value rate base over the original cost rate base. Such a procedure would still provide for a return being earned on all investor-supplied funds and thus be consistent with financial and regulatory standards.

Q. Has the staff made such a proposal in this proceeding?

A. Yes, it has. Staff witness Ralph Smith has re-cast my cost of capital calculation in a fashion that incorporates my surrebuttal position. As this indicates, the "fair value cost of capital" for UNS Electric is 7.01 percent.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
EXECUTIVE VICE PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies.

Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's

Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association,
Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
			1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	6.1%	4.5%	1.6%	0.0%
1999	4.5%	4.7%	4.2%	2.7%	2.9%
2000	3.7%	4.5%	4.0%	3.4%	3.6%
2001	0.8%	-3.5%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.6%	0.0%	5.8%	2.4%	1.2%
2003	2.5%	1.1%	6.0%	1.9%	4.0%
2004	3.9%	2.5%	5.5%	3.3%	4.2%
2005	3.2%	3.2%	5.1%	3.4%	5.4%
2006	3.3%	3.9%	4.6%	2.5%	1.1%
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.7%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.7%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.2%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	3.6%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	4.3%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	4.0%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	3.3%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.8%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	3.3%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.8%	2.7%	5.0%	8.8%	14.0%
4th Qtr.					
2006					
1st Qtr.	5.6%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.6%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	2.0%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	2.5%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	1.3%	2.6%	4.5%	4.8%	2.8%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%		7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
2003							
Jan	4.25%	1.17%	4.05%		6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%		6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%		6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%		6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%		6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%		6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%		6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%		6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%		6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%		6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%		6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%		6.18%	6.27%	6.61%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.94%	4.60%		5.61%	5.80%	6.04%
Dec		4.85%	4.56%		5.62%	5.81%	6.05%
2007							
Jan	8.25%	4.96%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988			2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,224.14	2,149.20	10,544.06	1.83%	
4th Qtr					
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.88%
3rd Qtr.	1,288.40	2,141.97	11,584.69	1.91%	5.88%
4th Qtr	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%

Source: Council of Economic Advisors, Economic Indicators, various issues.

UNISOURCE ENERGY
SEGMENT FINANCIAL INFORMATION
2003 - 2005
($millions)

Segment	Operating Revenue	Net Income	Total Assets
		2003	
Tucson Electric Power	$852 87.6%	$129 113.2%	$2,767 88.6%
UNS Gas 1/	$47 4.8%	$1 0.9%	$185 5.9%
UNS Electric 1/	$56 5.8%	$2 1.8%	$125 4.0%
Global Solar	$2 0.2%	-$7 -6.1%	$26 0.8%
UniSource Energy Consolidated	$973	$114	$3,123
		2004	
Tucson Electric Power	$889 76.0%	$46 100.0%	$2,742 86.3%
UNS Gas	$129 11.0%	$6 13.0%	$201 6.3%
UNS Electric	$144 12.3%	$4 8.7%	$135 4.3%
Global Solar	$5 0.4%	-$5 -10.9%	$20 0.6%
UniSource Energy Consolidated	$1,169	$46	$3,176
		2005	
Tucson Electric Power	$937 76.2%	$48 104.3%	$2,575 82.3%
UNS Gas	$138 11.2%	$5 10.9%	$233 7.5%
UNS Electric	$150 12.2%	$5 10.9%	$161 5.1%
Global Solar	$5 0.4%	-$7 -15.2%	$20 0.6%
UniSource Energy Consolidated	$1,230	$46	$3,127
		2006	
Tucson Electric Power	$998 75.8%	$67 100.0%	$2,623 82.3%
UNS Gas	$162 12.3%	$4 6.0%	$253 7.9%
UNS Electric	$160 12.1%	$5 7.5%	$195 6.1%
UniSource Energy Consolidated	$1,317	$67	$3,187

1/ 2003 figures for UNS Gas and UNS Electric are for period August 11 through December 31.

Note: Totals may not add to 100.0% due to "All Others" and "Reconciling Adjustments."

Source: UniSource Energy Annual Report.

UNS ELECTRIC
CAPITAL STRUCTURE RATIOS
2003 - 2006
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2003	$36.6	$60.0	$0.7
	37.6%	61.7%	0.7%
	37.9%	62.1%	
2004	$40.9	$60.0	$0.6
	40.3%	59.1%	0.6%
	40.5%	59.5%	
2005	$49.9	$60.0	$0.5
	45.2%	54.3%	0.5%
	45.4%	54.6%	
2006	$64.9	$79.0	$0.4
	45.0%	54.7%	0.3%
	45.1%	54.9%	

Note: Percentages may not total 100.0% due to rounding.

Debt figures exclude capital lease obligations.

Source: Response to STF 4.8.

UNISOURCE ENERGY
CAPITAL STRUCTURE RATIOS
2002 - 2006
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2002	$456,640	$0	$1,128,963	$0
	28.8%	0.0%	71.2%	0.0%
	28.8%	0.0%	71.2%	
2003	$556,472	$0	$1,286,320	$0
	30.2%	0.0%	69.8%	0.0%
	30.2%	0.0%	69.8%	
2004	$580,718	$0	$1,257,595	$0
	31.6%	0.0%	68.4%	0.0%
	31.6%	0.0%	68.4%	
2005	$616,741	$0	$1,212,420	$5,000
	33.6%	0.0%	66.1%	0.3%
	33.7%	0.0%	66.3%	
2006	$654,149	$0	$1,171,170	$50,000
	34.9%	0.0%	62.5%	2.7%
	35.8%	0.0%	64.2%	

Note: Percentages may not total 100.0% due to rounding.

Source: UniSource Energy Annual Report.

UNISOURCE ENERGY AND UTILITY SUBSIDIARIES
CAPITAL STRUCTURE RATIOS
December 31, 2006
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
Unisource Energy Consolidated	$654.1 34.9% 35.8%	$1,171.2 62.5% 64.2%	$50.0 2.7%
Tucson Electric Power Company	$554.7 40.3% 40.3%	$821.2 59.7% 59.7%	$0.0 0.0%
UniSource Energy Services	$149.4 45.5% 45.5%	$179.0 54.5% 54.5%	$0.0 0.0%
UNS Electric	$64.9 45.1% 45.1%	$79.0 54.9% 54.9%	$0.0 0.0%
UNS Gas	$84.2 45.7% 45.7%	$100.0 54.3% 54.3%	$0.0 0.0%

Note: Percentages may not total 100.0% due to rounding.

Source: Response to STF 4.8.

Exhibit___(DCP-1)
Schedule 5

AUS UTILITY REPORTS
ELECTRIC UTILITY GROUPS
AVERAGE COMMON EQUITY RATIOS

Year	Electric	Combination Electric and Gas
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%
2006	45%	44%

Note: Averages include short-term debt.

Source: AUS Utility Reports.

Exhibit___(DCP-1)
Schedule 6

COMPARISON COMPANIES
BASIS FOR SELECTION

Company	Market Cap (000)	Percent Revenues Electric	Common Equity Ratio	Value Line Safety	Moody's/ S&P Bond Rating	S&P Stock Ranking
Unisource Energy	$1,400	85%	25%	3	BBB- / BAA2	B
Comparison Group*						
Avista Corp.	$1,200	50%	41%	3	BBB- / BAA3	B
Cleco Corp.	$1,500	96%	52%	3	BBB / BAA1	B+
DPL, Inc.	$3,400	100%	38%	3	BBB / NR	B+
Hawaiian Electric	$2,200	84%	53%	2	BBB / BAA2	B+
Northeast Utilities	$4,500	77%	35%	3	BBB / BAA1	B
Pepco Holdings, Inc.	$5,100	58%	42%	3	BBB+ / BAA1	B
PG&E Corp.	$1,900	70%	50%	2	BBB / BAA1	B
PNM Resources	$2,100	79%	42%	2	BBB / BAA2	B+
Puget Energy, Inc.	$3,000	61%	46%	3	BBB / BAA2	B

* Selected using following criteria:
Market cap of $1 billion to $8 billion.
Electric Revenues of 40% or greater.
Common Equity Ratio of 35% or greater.
Value Line Safety of 1, 2 or 3.
S&P bond ratings of BBB and Moody's bond ratings of Baa.
S&P stock ranking of B or B+.

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	March-May 2007 Stock Prices HIGH	LOW	AVERAGE	YIELD
Comparison Group					
Avista Corp.	$0.60	$24.89	$22.88	$23.89	2.5%
Cleco Corp.	$0.90	$29.20	$24.83	$27.02	3.3%
DPL, Inc.	$1.04	$32.72	$29.58	$31.15	3.3%
Hawaiian Electric	$1.24	$26.73	$24.50	$25.62	4.8%
Northeast Utilities	$0.75	$33.62	$28.20	$30.91	2.4%
Pepco Holdings, Inc.	$1.04	$30.71	$25.85	$28.28	3.7%
PG&E Corp.	$1.44	$52.17	$45.10	$48.64	3.0%
PNM Resources	$0.92	$34.28	$28.50	$31.39	2.9%
Puget Energy, Inc.	$1.00	$26.91	$24.00	$25.46	3.9%
Average					**3.3%**
Grant Combination Gas and Electric Utilities Group					
CH Energy Group, Inc.	$2.16	$50.78	$45.93	$48.36	4.5%
Cleco Corp.	$0.90	$29.20	$24.83	$27.02	3.3%
Hawaiian Electric	$1.24	$26.73	$24.50	$25.62	4.8%
MGE Energy Inc.	$1.39	$37.02	$33.05	$35.04	4.0%
Northeast Utilities	$0.75	$33.62	$28.20	$30.91	2.4%
NSTAR	$1.30	$37.37	$33.36	$35.37	3.7%
Puget Energy, Inc.	$1.00	$26.91	$24.00	$25.46	3.9%
UIL Holdings	$1.73	$37.01	$32.80	$34.91	5.0%
Average					**4.0%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2002	2003	2004	2005	2006	Average	2007	2008	2010-12	Average
Comparison Group										
Avista Corp.	1.2%	3.4%	1.4%	2.4%	4.9%	2.7%	3.5%	4.0%	2.0%	3.2%
Cleco Corp.	5.6%	3.5%	3.9%	4.1%	3.0%	4.0%	2.0%	2.5%	3.0%	2.5%
DPL, Inc.	0.0%	2.2%	9.8%	0.8%	9.0%	4.4%	10.0%	9.0%	6.5%	8.5%
Hawaiian Electric	4.3%	3.9%	1.1%	1.5%	0.7%	2.3%	0.5%	1.5%	3.5%	1.8%
Northeast Utilities	3.2%	3.7%	1.6%	1.5%	5.0%	3.0%	4.0%	4.0%	4.0%	4.0%
Pepco Holdings, Inc.	5.3%	2.0%	2.5%	2.4%	1.5%	2.7%	3.0%	4.0%	5.5%	4.2%
PG&E Corp.	0.0%	18.5%	10.3%	7.7%	6.6%	8.6%	6.0%	5.5%	4.5%	5.3%
PNM Resources	3.1%	3.0%	4.5%	4.3%	3.7%	3.7%	4.0%	3.5%	3.0%	3.5%
Puget Energy, Inc.	1.3%	2.1%	2.8%	2.9%	3.0%	2.4%	3.0%	3.5%	4.0%	3.5%
Average						**3.8%**				**4.1%**
Grant Combination Gas and Electric Utilities Group										
CH Energy Group, Inc.	0.0%	2.0%	1.7%	2.0%	1.5%	1.4%	1.5%	1.5%	2.0%	1.7%
Cleco Corp.	5.6%	3.5%	3.9%	4.1%	3.0%	4.0%	2.0%	2.5%	3.0%	2.5%
Hawaiian Electric	4.3%	3.9%	1.1%	1.5%	0.7%	2.3%	0.5%	1.5%	3.5%	1.8%
MGE Energy Inc.	2.6%	2.5%	2.3%	2.5%	3.5%	2.7%	4.0%	4.0%	3.0%	3.7%
Northeast Utilities	3.2%	3.7%	1.6%	1.5%	5.0%	3.0%	4.0%	4.0%	4.0%	4.0%
NSTAR	5.2%	5.2%	4.9%	4.7%	2.5%	4.5%	5.0%	5.5%	6.0%	5.5%
Puget Energy, Inc.	1.3%	2.1%	2.8%	2.9%	3.0%	2.4%	3.0%	3.5%	4.0%	3.5%
UIL Holdings	0.6%	0.0%	0.0%	0.0%	0.5%	0.2%	0.5%	1.0%	1.5%	1.0%
Average						**2.6%**				**3.0%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '04-'06 to '10-'12 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Comparison Group								
Avista Corp.	0.5%	2.5%	3.5%	2.2%	12.0%	12.5%	5.0%	9.8%
Cleco Corp.	1.0%	2.0%	4.0%	2.3%	4.0%	4.0%	6.5%	4.8%
DPL, Inc.	-1.0%	0.5%	-1.0%	-0.5%	8.0%	7.5%	5.0%	6.8%
Hawaiian Electric	-1.0%	0.0%	2.0%	0.3%	4.0%	0.0%	0.5%	1.5%
Northeast Utilities	0.0%	30.5%	3.0%	11.2%	8.5%	6.5%	1.5%	5.5%
Pepco Holdings, Inc.	-1.0%	0.0%	0.5%	-0.2%	8.0%	3.0%	3.0%	4.7%
PG&E Corp.	0.0%	-1.5%	9.5%	2.7%	4.0%	0.0%	6.0%	3.3%
PNM Resources	-2.5%	7.5%	4.5%	3.2%	4.5%	8.0%	5.5%	6.0%
Puget Energy, Inc.	-4.5%	-11.5%	1.5%	-4.8%	6.0%	3.0%	4.0%	4.3%
Average				**1.8%**				**5.2%**
Grant Combination Gas and Electric Utilities Group								
CH Energy Group, Inc.	-1.5%	0.0%	2.0%	0.2%	1.0%	0.5%	1.5%	1.0%
Cleco Corp.	1.0%	2.0%	4.0%	2.3%	4.0%	4.0%	6.5%	4.8%
Hawaiian Electric	-1.0%	0.0%	2.0%	0.3%	4.0%	0.0%	0.5%	1.5%
MGE Energy Inc.	2.0%	1.0%	6.5%	3.2%	6.0%	50.0%	7.0%	21.0%
Northeast Utilities	0.0%	30.5%	3.0%	11.2%	8.5%	6.5%	1.5%	5.5%
NSTAR	4.0%	1.0%	2.0%	2.3%	7.5%	8.0%	6.0%	7.2%
Puget Energy, Inc.	-4.5%	-11.5%	1.5%	-4.8%	6.0%	3.0%	4.0%	4.3%
UIL Holdings	-9.0%	0.0%	2.0%	-2.3%	6.0%	0.0%	2.0%	2.7%
Average				**1.5%**				**6.0%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group								
Avista Corp.	2.6%	2.7%	3.2%	2.2%	9.8%	5.5%	4.7%	7.2%
Cleco Corp.	3.4%	4.0%	2.5%	2.3%	4.8%	12.0%	5.1%	8.6%
DPL, Inc.	3.5%	4.4%	8.5%		6.8%	10.0%	7.4%	10.9%
Hawaiian Electric	4.9%	2.3%	1.8%	0.3%	1.5%	3.0%	1.8%	6.7%
Northeast Utilities	2.5%	3.0%	4.0%	11.2%	5.5%	12.0%	7.1%	9.7%
Pepco Holdings, Inc.	3.8%	2.7%	4.2%		4.7%	10.0%	5.4%	9.2%
PG&E Corp.	3.0%	8.6%	5.3%	2.7%	3.3%	8.0%	5.6%	8.6%
PNM Resources	3.0%	3.7%	3.5%	3.2%	6.0%	10.0%	5.3%	8.3%
Puget Energy, Inc.	4.0%	2.4%	3.5%		4.3%	4.0%	3.6%	7.6%
Average	3.4%	3.8%	4.1%	3.6%	5.2%	8.3%	5.1%	**8.5%**
Median								**8.6%**
Composite		7.2%	7.5%	7.0%	8.6%	**11.7%**	8.5%	
Grant Combination Gas and Electric Utilities Group								
CH Energy Group, Inc.	4.5%	1.4%	1.7%	0.2%	1.0%		1.1%	5.6%
Cleco Corp.	3.4%	4.0%	2.5%	2.3%	4.8%	12.0%	5.1%	8.6%
Hawaiian Electric	4.9%	2.3%	1.8%	0.3%	1.5%	3.0%	1.8%	6.7%
MGE Energy Inc.	4.1%	2.7%	3.7%	3.2%	21.0%		7.6%	11.8%
Northeast Utilities	2.5%	3.0%	4.0%	11.2%	5.5%	12.0%	7.1%	9.7%
NSTAR	3.8%	4.5%	5.5%	2.3%	7.2%	6.0%	5.1%	8.9%
Puget Energy, Inc.	4.0%	2.4%	3.5%		4.3%	4.0%	3.6%	7.6%
UIL Holdings	5.0%	0.2%	1.0%		2.7%	8.0%	3.0%	8.0%
Average	4.0%	2.6%	3.0%	3.3%	6.0%	7.5%	4.3%	**8.3%**
Median								**8.3%**
Composite		6.6%	7.0%	7.3%	10.0%	**11.5%**	8.3%	

Sources: Prior pages of this schedule.

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.26%	5.11%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
Average			**14.09%**	**7.90%**	**6.19%**

Sources: Standard & Poor's Analysts' Handbook and Ibbotson Associates 2006 Yearbook.

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	MARKET RETURN	CAPM RATES
Comparison Group				
Avista Corp.	4.91%	0.95	5.90%	10.5%
Cleco Corp.	4.91%	1.30	5.90%	12.6%
DPL, Inc.	4.91%	0.95	5.90%	10.5%
Hawaiian Electric	4.91%	0.75	5.90%	9.3%
Northeast Utilities	4.91%	0.90	5.90%	10.2%
Pepco Holdings, Inc.	4.91%	0.90	5.90%	10.2%
PG&E Corp.	4.91%	1.20	5.90%	12.0%
PNM Resources	4.91%	0.95	5.90%	10.5%
Puget Energy, Inc.	4.91%	0.85	5.90%	9.9%
Average				**10.6%**
Median				**10.5%**
Grant Combination Gas and Electric Utilities Group				
CH Energy Group, Inc.	4.91%	0.85	5.90%	9.9%
Cleco Corp.	4.91%	1.30	5.90%	12.6%
Hawaiian Electric	4.91%	0.75	5.90%	9.3%
MGE Energy Inc.	4.91%	0.80	5.90%	9.6%
Northeast Utilities	4.91%	0.90	5.90%	10.2%
NSTAR	4.91%	0.80	5.90%	9.6%
Puget Energy, Inc.	4.91%	0.85	5.90%	9.9%
UIL Holdings	4.91%	0.95	5.90%	10.5%
Average				**10.2%**
Median				**9.9%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	1992-2001 Average	2002-2006 Average	2007	2008	2010-12
Comparison Group																				
Avista Corp.	11.7%	12.2%	10.5%	11.2%	10.6%	15.0%	10.2%	1.1%	13.4%	7.9%	4.5%	6.7%	4.7%	4.5%	8.9%	10.4%	5.8%	6.5%	7.5%	8.0%
Cleco Corp.	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	9.5%	13.5%	11.7%	8.0%	8.0%	10.0%
DPL, Inc.	13.3%	14.5%	15.1%	15.2%	15.5%	15.4%	14.9%	15.2%	18.6%	26.5%	11.3%	15.7%	22.7%	12.2%	21.4%	16.4%	16.7%	25.5%	24.0%	18.5%
Hawaiian Electric	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	11.0%	10.3%	9.5%	10.0%	12.0%
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	5.4%	0.0%	3.8%	4.8%	8.5%	8.5%	8.5%
Pepco Holdings, Inc.	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	7.2%	11.0%	8.2%	8.5%	9.5%	11.0%
PG&E Corp.	13.6%	11.9%	13.9%	14.4%	10.4%	7.5%	8.9%	11.2%	-67.5%	30.1%	-22.1%	20.9%	13.8%	11.7%	13.7%	5.4%	7.6%	12.0%	12.0%	10.5%
PNM Resources	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.9%	8.6%	8.4%	10.0%	7.6%	8.0%	8.0%	7.5%
Puget Energy, Inc.	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	8.4%	8.1%	10.4%	7.9%	8.5%	8.5%	9.5%
Average	11.5%	11.4%	11.9%	11.8%	10.3%	9.3%	10.0%	8.5%	2.3%	15.0%	5.5%	10.5%	10.3%	8.9%	9.6%	**10.2%**	**9.0%**	**10.6%**	**10.7%**	**10.6%**
Composite																**10.2%**	**9.0%**			
Grant Combination Gas and Electric Utilities Group																				
CH Energy Group, Inc.	11.0%	11.1%	10.7%	10.7%	11.3%	10.9%	10.4%	10.2%	10.5%	10.4%	7.0%	9.1%	8.7%	8.9%	8.4%	10.7%	8.4%	8.0%	8.0%	8.5%
Cleco Corp.	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	9.5%	13.5%	11.7%	8.0%	8.0%	10.0%
Hawaiian Electric	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	11.0%	10.3%	9.5%	10.0%	12.0%
MGE Energy Inc.	13.1%	13.3%	13.1%	12.5%	7.1%	12.5%	12.2%	13.0%	14.2%	13.1%	13.2%	12.5%	11.4%	9.4%	12.2%	12.4%	11.8%	12.0%	12.0%	10.5%
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	5.4%	0.0%	3.8%	4.8%	8.5%	8.5%	8.5%
NSTAR	11.4%	11.9%	12.2%	10.2%	12.6%	12.6%	12.5%	11.4%	12.3%	13.4%	14.0%	13.9%	13.4%	13.1%	13.2%	12.1%	13.5%	13.5%	14.0%	15.0%
Puget Energy, Inc.	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	8.4%	8.1%	10.4%	7.9%	8.5%	8.5%	9.5%
UIL Holdings	10.8%	10.4%	10.9%	11.8%	10.1%	10.4%	9.5%	11.5%	12.8%	12.1%	8.9%	6.1%	7.5%	5.2%	8.3%	11.0%	7.2%	8.0%	8.5%	8.0%
Average	12.0%	11.2%	11.6%	11.5%	9.5%	8.9%	9.8%	9.3%	10.8%	11.5%	10.3%	9.8%	9.5%	9.0%	8.6%	**10.6%**	**9.5%**	**9.5%**	**9.7%**	**10.3%**
Composite																**10.6%**	**9.5%**			

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	1992-2001 Average	2002-2006 Average
Comparison Group																	
Avista Corp.	151%	163%	133%	125%	145%	162%	163%	152%	317%	114%	85%	94%	111%	117%	136%	163%	109%
Cleco Corp.	177%	175%	156%	162%	168%	171%	183%	172%	223%	224%	154%	134%	177%	177%	162%	181%	161%
DPL, Inc.	177%	206%	196%	213%	214%	221%	231%	215%	314%	422%	321%	235%	263%	320%	382%	241%	304%
Hawaiian Electric	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	147%	171%
Northeast Utilities	154%	149%	127%	124%	95%	64%	91%	113%	136%	129%	99%	95%	106%	108%	0%	118%	82%
Pepco Holdings, Inc.	160%	162%	135%	138%	161%	151%	161%	166%	139%	124%	110%	103%	109%	122%	130%	150%	115%
PG&E Corp.	168%	175%	142%	134%	115%	123%	152%	135%	179%	136%	149%	203%	196%	179%	208%	146%	187%
PNM Resources	72%	84%	87%	95%	108%	106%	106%	85%	94%	123%	95%	93%	124%	147%	134%	96%	119%
Puget Energy, Inc.	149%	146%	112%	119%	130%	155%	170%	146%	143%	143%	126%	129%	137%	133%	129%	141%	131%
Average	153%	157%	136%	140%	143%	145%	157%	146%	186%	173%	143%	138%	156%	165%	164%	**154%**	**153%**
Composite																**154%**	**153%**
Grant Combination Gas and Electric Utilities Group																	
CH Energy Group, Inc.	123.2%	133.1%	106.6%	111.7%	114.1%	135.3%	154.6%	132.9%	124.6%	141.0%	152.2%	147.1%	149.3%	145.9%	154.0%	128%	150%
Cleco Corp.	177.3%	174.9%	156.2%	162.2%	167.8%	170.8%	182.5%	172.3%	222.8%	224.3%	154.1%	134.5%	176.9%	176.6%	162.5%	181%	161%
Hawaiian Electric	170.8%	153.9%	141.2%	149.1%	147.0%	147.1%	154.1%	131.8%	126.7%	145.1%	153.3%	150.9%	178.8%	181.2%	191.8%	147%	171%
MGE Energy Inc.	189.0%	196.5%	188.9%	183.3%	203.5%	188.9%	196.5%	176.5%	172.0%	197.0%	213.6%	222.8%	206.9%	207.4%	196.0%	189%	209%
Northeast Utilities	154.2%	149.4%	127.0%	123.5%	94.5%	64.3%	90.7%	113.3%	136.4%	129.0%	99.4%	95.3%	105.5%	108.4%	0.0%	118%	82%
NSTAR	138.4%	153.9%	130.0%	129.6%	124.7%	146.4%	180.8%	165.8%	160.8%	161.3%	170.2%	174.6%	189.3%	202.2%	213.9%	149%	190%
Puget Energy, Inc.	149.2%	146.4%	111.7%	119.5%	130.0%	155.2%	169.7%	145.8%	143.4%	143.5%	125.9%	128.9%	137.5%	132.7%	129.0%	141%	131%
UIL Holdings	129.1%	140.2%	113.8%	110.4%	113.9%	111.2%	151.5%	143.8%	140.9%	139.4%	125.8%	112.7%	141.6%	122.6%	158.4%	129%	132%
Average	154%	156%	134%	136%	137%	140%	160%	148%	153%	160%	149%	146%	161%	160%	151%	**148%**	**153%**
Composite																**148%**	**153%**

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2005

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
Averages:		
1992-2001	14.7%	341%
2001-2005	12.2%	299%

Source: Standard & Poor's Analyst's Handbook, 2006 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Comparison Group	2.7	0.97	B+	B+
Grant Gas & Electric Group	2.1	0.90	B++	B+

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the latter representing the highest level.

UNS ELECTRIC
TOTAL COST OF CAPITAL

ITEM	PERCENT		COST RATE		WEIGHTED COST	
Short-Term Debt	3.96%		6.36%		0.25%	
Long-Term Debt	47.21%		8.16%		3.85%	
Common Equity	48.83%	9.50%		10.50%	4.64%	5.13%
Total	100.00%				**8.74%**	**9.23%**
						8.99% Mid-point

UNS ELECTRIC
PRE-TAX COVERAGE

ITEM	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST	
Short-Term Debt	3.96%	6.36%	0.25%	0.25%	
Long-Term Debt	47.21%	8.16%	3.85%	3.85%	
Common Equity	48.83%	10.00%	4.88%	8.23%	(1)
TOTAL CAPITAL	100.00%		8.99%	12.33%	

(1) Post-tax weighted cost divided by .59345 (composite tax factor)

Pre-tax coverage = 12.33%/(0.25%+3.85%)
3.00 X

Standard & Poor's Utility Benchmark Ratios:

	BBB	A
Pre-tax coverage (X)		
Business Position:		
3	1.8 - 2.8x	2.8-3.4x
Total Debt to Total Capital (%)		
Business Position		
3	55 - 65%	50 - 55%

Note that a business position of "3" is shown here since S&P places most transmission and distribution utilities in a range of "1" to "4".

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BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

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 AND REQUEST FOR APPROVAL OF RELATED FINANCING	DOCKET NO. E-04204A-06-0783

SURREBUTTAL

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

AUGUST 24, 2007

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III.	Financial Integrity/Capital Attraction	6

I. INTRODUCTION

Q. Please state your name and address.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is 1051 East Cary Street, Suite 601, Richmond, VA 23219.

Q. Are you the same David C. Parcell who filed Direct Testimony on behalf of the Commission Staff in this proceeding?

A. Yes, I am.

Q. What is the purpose of your current testimony?

A. My current testimony is Surrebuttal Testimony in response to the Rebuttal Testimony of UNS Electric witness Kentton C. Grant.

Q. What aspects of Mr. Grant's Rebuttal Testimony do you respond to in this Surrebuttal Testimony?

A. My Surrebuttal Testimony responds to the following general areas of Mr. Grant's Rebuttal Testimony:

Cost of Common Equity; and,

Financial Integrity/Capital Attraction of UNS Electric.

II. COST OF COMMON EQUITY

Q. What are the primary differences in your cost of equity recommendations and the cost of equity recommendations of Mr. Grant?

A. The primary difference in our respective cost of equity analyses revolves around the top ends of our Capital Asset Pricing Model ("CAPM") analyses. As I indicated in my Direct

Testimony (Page 31, lines 26-28) and as Mr. Grant acknowledges in his Rebuttal Testimony (Page 21, Lines 12-14), our respective Discounted Cash Flow ("DCF") results are very similar. In addition, our CAPM analyses produce similar results, except for the upper end of the ranges, as follows:

	DCF	CAPM
Parcell	9.50%-10.50%	10.00%-10.50%
Grant	9.70%-10.50% (10.4% median)	9.80%-11.20% (10.5% median)

This indicates that Mr. Grant and I agree with regard to our DCF results and most of our CAPM results. In addition, Mr. Grant's proposal to add 60 basis points to his cost of equity conclusions for his proxy group is unnecessary, as I indicated in my Direct Testimony.

Q. What are your comments about Mr. Grant's CAPM methodology and his comments on your CAPM methodology in his Rebuttal Testimony?

A. As I indicated in my Direct Testimony (Page 32, Lines 8-16) and as Mr. Grant acknowledges in his Rebuttal Testimony (Page 21, Lines 22-26), the primary difference in our respective CAPM methodologies is his use of an equity risk premium (7.1 percent) that relies exclusively on the arithmetic means of common stock returns and bond returns over the period 1926-2005.

Q. Mr. Grant claims, on pages 21-22, that it is appropriate to use only arithmetic returns, and ignore geometric (compound) returns in deriving the risk premium component of the CAPM. Do you have any comments on this claim?

A. Yes, I do. What is important is not what Mr. Grant and I believe, but what investors rely upon in making investment decisions. It is apparent that investors have access to both

types of returns, and correspondingly use both types of returns, when they make investment decisions.

In fact, it is noteworthy that mutual fund investors regularly receive reports on their own funds, as well as prospective funds they are considering investing in that show only geometric returns. Based on this, I find it difficult to accept Mr. Grant's position that only arithmetic returns are considered by investors and, thus, only arithmetic returns are appropriate in a CAPM context. I note that I provided additional comments on this point in my Direct Testimony.

Q. Mr. Grant also takes issue with your comparable earnings analysis. Do you have any response to his assertions?

A. Yes, I do. Mr. Grant apparently believes that, if electric utilities, such as UNS Electric, have and are earning returns on equity of over 10 percent and simultaneously are enjoying a market-to-book ratio of about 150 percent, then the earned levels represent the cost of capital for the electric utilities. I disagree with this position. Investors know that the vast majority of utilities are regulated based upon the book value of their assets (i.e., rate base) and their liabilities (i.e., capitalization). It is logical and intuitive that investors would only pay a stock price that substantially exceeds book value for a utility if there is an expectation that the company is earning a return that exceeds its cost of capital. Mr. Grant ignores this in his Rebuttal Testimony.

Q. Mr. Grant also asserts, on pages 23-24, that you did not take into account any "company-specific risk factors" in your cost of equity recommendation. Do you have any response to this assertion?

A. Yes, I do. The primary "Company-specific risk factor" that Mr. Grant cites is the "size" of UNS Electric. Mr. Grant apparently believes that UniSource Energy's decision to maintain UNS Electric as a separate subsidiary, in contrast to merging it into Tucson Electric Power and/or UniSource Energy, should have the effect of raising its cost of equity. I disagree with this assertion. UNS Electric does not raise equity capital in the marketplace; rather it is raised by UniSource Energy based on the combined financial strength of all of its operations. If UNS Electric and every other subsidiary of UniSource Energy received a higher cost of equity due to their respective "small" sizes, each subsidiary, as well as UniSource Energy as a whole, would earn an excessive return.

This point is verified by UNS Electric's response to STF 4.3, which indicates that UniSource Energy Services ("UES") provided the cash investment portion of the purchase of the Citizens Utilities properties that became UNS Electric. This response also indicates that UES was an "intermediate holding company formed by UniSource Energy Corporation," apparently for the purpose of obtaining the Citizens properties in Arizona and for ownership of UNS Gas and UNS Electric. This response further indicates that UES obtained the cash it infused into UNS Electric from UniSource Energy. Thus, the link between the financing of UNS Electric and UniSource Energy is demonstrated.

In addition, the response to STF 4.9 verifies that UES is "listed as the guarantor in the 2003 sale and purchase agreement for $60 million of long-term notes and in the 2006 revolving credit agreement (as amended) with a syndicate of banks." This also demonstrates the financial linkage between UNS Electric and UES/UniSource Energy.

Finally, the response to STF 4.19 indicates Mr. Grant's acknowledgement that the "size impact on risk of UNS Electric . . . would be reduced if UNS Electric were merged into Tucson Electric." This indicates that this risk factor is within the control of the management of UniSource Energy.

Q. Mr. Grant also claims, on page 24, lines 1-7, and again on page 26, lines 21-27, that your cite of a 2003 Standard and Poor's report is no longer relevant. Do you have any response to this assertion?

A. Yes, I do. The source of the 2003 Standard & Poor's ("S&P") report is UNS Electric's response to STF 4.1, which requested "all reports by rating agencies" that describe the acquisition of UNS Electric by UniSource Energy. Since there have been no subsequent descriptions of the Company, it is evident from the S&P reports supplied by the Company in its DR response that S&P does not perceive that UNS Electric's financial status has changed since the cited report was prepared. The absence of any modification of these quotes by S&P is indicative that this agency's position of the Company has not changed since the cited report.

Q. Mr. Grant claims, on pages 24-25, that UNS Electric does not have investment-grade debt. Do you have any comments on this?

A. Yes, I do. UNS Electric's only debt is $60 million in notes issued to finance the Arizona Citizens properties. The notes were "issued pursuant to a private placement to institutional investors in 2003" (response to STF 4.12). Thus, these notes were issued to finance the purchase, which is a different scenario than most utility note issues.

III. FINANCIAL INTEGRITY/CAPITAL ATTRACTION

Q. Mr. Grant claims, on page 26, lines 7-17, that UNS Electric would not likely earn the return you recommend as a result of recommendations of other Staff witnesses. Do you have any response to this?

A. Yes, I do. The respective recommendations of other Staff witnesses in this proceeding reflect their own recommendations based upon their own analyses of UNS Electric's application and their own implementation of proper rate-making standards. To the extent that the Commission adopts any or all Staff recommendations, this is reflective of regulatory acceptance of the positions taken by Staff. Any corresponding reduction in the Company's potential earned rate of return would thus be appropriate from a regulatory and rate-making standpoint.

Q. Are there any other factors that impact the "financial metrics" of UNS Electric?

A. Yes, there are. When UniSource Energy purchased what is now UNS Electric in 2003, it agreed to a "rate freeze" that is still in effect. The response to STF 4.14 acknowledged that "the Company's earnings and cash flow have been negatively impacted over the period 2004 through 2006, and are expected to remain at depressed levels until rate relief is granted in this docket (assumed to occur in 2008 in this exhibit)." I note that Mr. Grant does not acknowledge the rate freeze and its impact on the Company's financial metrics when he describes the "financial integrity" of the Company.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

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BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDEL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

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 AND REQUEST FOR APPROVAL OF RELATED FINANCING	DOCKET NO. E-04204A-06-0783

DIRECT

TESTIMONY

OF

ALEXANDER IBHADE IGWE

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 28, 2007

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

On December 15, 2006, UNS Electric, Inc. ("UNS" or "Company") filed an application with the Arizona Corporation Commission ("Commission") for a rate increase and for approval of financing. My testimony addresses UNS' request for financing approval in this proceeding. The Company's request for rate recovery for Black Mountain Generating Station ("BMGS") is addressed in Staff witness Mr. Smith's testimony.

UNS requests Commission authorization to incur up to $40 million in new debt financing and to receive up to $40 million of new equity infusion from its parent company, for an aggregate of up to $80 million. Also, the Company seeks flexibility to issue a mix of short-term, intermediate-term and long-term debt, depending on prevailing market conditions at the time of debt issuance. Further, UNS seeks authorization to refinance any short-term or intermediate-term debt, issued in this proceeding, to long-term debt, without further Commission approval. UNS states that the terms of its proposed debt financing are currently unknown, and would be contingent upon prevailing market conditions as well as investors' assessment of its credit worthiness. The Company indicates that the proceeds of its proposed financing will be expended solely for the purpose of acquiring a 90 MW peaking facility, BMGS, at an estimated cost of between $60 and $65 million. The Company states that BMGS will be acquired at cost from its subsidiary, UniSource Electric Development Company ("UEDC"), and placed in service sometime around June 2008.

Staff concludes that this proposal is in the public interest and recommends approval. Staff's analysis indicates that if the proposed financing is issued in a 50/50 debt/equity configuration, it may have no material impact on Staff's recommended capital structure of 48.83 percent equity and 51.17 percent debt. Further, Staff finds that because of lack of specificity as to the terms of the proposed debt financing, pertinent parameters for measuring the Company's ability to service the debt obligations, such as Debt Service Coverage Ratio and Times Interest Earned Ratio, cannot be determined at this time.

In summary, Staff recommends the following:

1. That the Commission authorize UNS to incur up to $40 million in new debt financing and to receive up to $40 million in new equity infusion, for the sole purpose of acquiring BMGS.

2. That the Commission authorize UNS to issue up to $40 million in debt financing, as recommended in (1) above, in long-term debt, and in short-term to intermediate-term debt.

3. That the Commission authorize UNS to refinance any short-term and intermediate-term debt, issued under this docket, to long-term debt, without further Commission authorization.

4. That the Commission authorize UNS to issue guarantees and grant liens on some or all of its assets, including BMGS, and any other properties acquired subsequent to this transaction, to secure its obligation under the proposed debt issuance and to secure other obligations at the time such liens are granted.

5. That the Commission authorize UNS to engage in any transactions and to execute or cause to be executed any documents so as to effectuate the authorizations requested with this application.

6. That UNS file a report with Docket Control demonstrating that it had a DSC and a TIER equal to or greater than 1.0, at the time of new debt issuance, within 60 days from the close of each transaction under this docket.

7. That UNS file a report with Docket Control, within 60 days from the close of each financing package, describing the transaction and demonstrating that the terms are consistent with those generally available to comparable entities.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Alexander Ibhade Igwe. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. What is your current employment position?

A. I am employed with the Utilities Division of the Arizona Corporation Commission ("Commission") as an Executive Consultant III.

Q. Briefly describe your responsibilities as an Executive Consultant.

A. In my capacity as an Executive Consultant III, I perform complex financial analysis and make recommendations to the Commission on rate base, revenue requirement and rate design; for water, wastewater, electric and gas rate proceedings. Also, I provide recommendations on financing, merger and acquisitions, sales of assets, issuance and extension of Certificate of Convenience and Necessity as well as other ancillary matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Accounting from the University of Benin, Nigeria and a Master of Information Systems Management degree from Keller Graduate School of Management of Devry University. I was a Certified Public Accountant and a member of the American Institute of Certified Public Accountants. I have attended various training classes and courses regarding regulatory audits, rate-making, and other utility related matters. In addition, in my over eight years working for the Utilities Division, I have prepared Staff Reports and pre-filed testimonies and presented oral testimonies in several proceedings before the Commission.

PURPOSE OF TESTIMONY

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

A. I am presenting Staff's analysis and recommendations regarding UNS Electric, Inc.'s ("UNS" or "Company") application for financing approval relating to its proposed acquisition of the Black Mountain Generating Station ("BMGS"). The Company's request for rate recovery for BMGS is addressed in Staff witness Mr. Smith's testimony.

THE TRANSACTION

Q. Please provide a brief description of UNS' financing application

A. UNS seeks Commission authorization to issue up to $40 million in new debt financing and to receive up to $40 million in additional equity contribution from its parent company, UniSource Energy Corporation, for a total of up to $80 million. UNS states that its request for authority to obtain up to $80 million in new financing will allow it some flexibility in determining the appropriate mix of debt and equity financing to be used for the acquisition of BMGS. Also, the Company indicates that the proposed debt financing could be comprised of short-term, intermediate-term and long-term debt, depending on the prevailing market conditions, at the time of debt issuance. Finally, the Company requests Commission authorization to refinance any short-term or intermediate-term debt, incurred in relation to this financing, with long-term debt, without further Commission approval.

Q. What is the purpose of the proposed financing arrangements?

A. UNS states that the proposed financing is requested solely for the purpose of funding the acquisition of BMGS, from its subsidiary, UniSource Electric Development Company ("UEDC"). The Company estimates that the 90 MW peaking facility could cost between $60 million and $65 million upon completion in May, 2008.

Q. Why does UNS seek authorization to receive additional equity infusion from its parent company?

A. UNS states that the proposed equity infusion will provide it with the requisite funding for the acquisition of BMGS. The Company explains that its requested equity contribution under this proposal will be in addition to any other equity infusion previously authorized by the Commission in prior proceedings. Also, UNS contends that the requested mix of debt and equity financing is necessary to maintain a balanced capital structure, upon conclusion of this transaction.

Q. What is the Company's justification for seeking a mix of debt financing?

A. The Company states that its request for authorization to issue a mix of short-term, intermediate-term and long-term debt financing, if necessary, will allow it needed flexibility to optimize prevailing market conditions at the time of debt issuance. For example, if the Company finds that it is cost-effective to borrow short-term or intermediate-term debt, until market conditions become conducive for issuance of long-term debt, this request will avail it the flexibility to obtain an appropriate mix of debt financing.

Q. Did the Company specify the terms of its proposed long-term debt financing?

A. No. UNS states that the terms of the proposed debt financing will be contingent upon the prevailing market conditions as well as investors' assessment of its credit worthiness, at the time of debt issuance. However, the Company indicates that the proposed long-term debt could vary in maturity from five to thirty years, at a fixed interest rate. Also, UNS anticipates that the debt term could require a lump-sum principal payment, or some form of principal amortization. Furthermore, the Company indicates that its proposed debt securities may be effectuated through a private placement or public issue. As to

collaralization of the debt, UNS suggests that the debt financing could be unsecured or secured by BMGS assets or by a mortgage lien on all its properties, including future assets acquired subsequent to consummation of this transaction.

Q. What are the terms of UNS' proposed short-term and intermediate-term debt?

A. Again, the Company states that the terms will depend on the prospective investors' assessment of its credit worthiness and the prevailing market conditions at the time of debt issuance. UNS anticipates that the new short-term or intermediate-term debt will have maturities ranging from one month to five years, with variable or fixed interest rates. The Company projects that the principal amounts might be due in a single payment or through some form of amortization. If the proposed short-term or intermediate debt requires collateralization, the Company expects the security will be similar to those discussed above, in relation to its proposed long-term debt.

FINANCIAL ANALYSIS

Q. What is the impact of UNS' proposed financing on its capital structure?

A. The exact impact of UNS' proposed financing on its capital structure cannot be ascertained at this time. Although the Company specifically requests Commission authorization to issue up to $40 million of new debt financing, and to receive up to $40 million in new equity infusion, it also seeks some flexibility in determining an appropriate mix of debt and equity that would be issued when it engages in the transactions. Staff Consultant, David Parcell recommends a capital structure that is comprised of 48.83 percent equity, 47.21 percent long-term debt and 3.96 percent short-term debt (51.17 percent in aggregate debt). If the Company issues $40 million in new debt financing and receives $40 million in new equity infusion or engages in a different configuration of 50/50 debt/equity financing, the proposed financing will have no material impact on

Staff's recommended capital structure. The scenario described above will result in a capital structure that is consistent with the Company's expressed intent to maintain a balanced capital structure, subsequent to the conclusion of this transaction.

Q, Please comment on the Company's proposal to issue a mix of short-term, intermediate-term and long-term debt.

A. Staff agrees with UNS' assertion that it may be prudent to issue a mix of debt financing, consisting of short-term, intermediate-term and long-term debt, in order to optimize prevailing market conditions. Also, Staff accepts the Company's request for authorization to refinance any short-term and intermediate-term debt, issued in relation to this application, to long-term debt, without further Commission authorization. To request the Company to file for prior Commission authorization before refinancing any proposed short-term and intermediate-term debt, to long-term debt, could be burdensome and preclude the Company from taking advantage of fluid market conditions. However, Staff recommends that any future refinance of short-term and intermediate-term debt issued under this docket should be communicated to the Commission within 60 days of close of the transaction.

Q. Did Staff calculate any financial parameters in relation to UNS' request for authorization to issue debt?

A. Staff did not calculate the traditional parameters, such as Debt Service Coverage ("DSC") ratio or Times Interest Earned Ratio ("TIER"), for determining a utility's ability to service its debt obligations. Staff's ability to calculate DSC and TIER on UNS' proposed debt financing is hamstrung by the general nature of its application. For example, the Company's request indicates issuance of up to $40 million in new debt financing, which is

neither specific as to the exact debt amount nor composition of the proposed debt. Also, the other factors such as interest rates and durations, are vague at this time.

Q. Please explain the terms DSC ratio and TIER.

A. A DSC represents the number of times internally generated cash flow covers debt service (principal and interest) on debt financing. A DSC greater than 1.0 indicates that operating cash flow is adequate to make interest and principal payments on long-term debt. A DSC less than 1.0 indicates that cash flow generated from operations may not be adequate to fulfill debt obligations, and that funds from other sources may be required to avoid default.

TIER represents the number of times operating income will cover interest expense on long-term debt. A TIER greater than 1.0 means that operating income is sufficient to make interest payment on debt.

Q. Does Staff recommend any DSC or TIER in this proceeding?

A. Yes. Although, the DSC and TIER relating to UNS' proposed debt financing cannot be determined at this time, for the reasons discussed above, Staff recommends that UNS demonstrate that it meets a minimum DSC and a TIER, equal to or greater than 1.0, at the time of each debt issuance.

RECOMMENDATION

Q. What is Staff's recommending regarding UNS proposed financing?

A. Staff recommends the following:

1. That the Commission approve UNS request to incur up to $40 million in new debt financing and to receive up to $40 million in new equity infusion, for the sole purpose of acquiring BMGS.
2. That the Commission authorize UNS to issue up to $40 million in debt financing, as recommended in (1) above, in long-term debt, and in short-term to intermediate-term debt.
3. That the Commission authorize UNS to refinance any short-term and intermediate-term debt, issued under this docket, to long-term debt, without further Commission authorization.
4. That the Commission authorize UNS to issue guarantees and grant liens on some or all of its assets, including BMGS, and any other properties acquire subsequent to this transaction, to secure its obligation under the proposed debt issuance and to secure other obligations at the time such liens are granted.
5. That the Commission authorize UNS to engage in any transactions and to execute or cause to be executed any documents so as to effectuate the authorizations requested with this application.
6. That UNS file a report with Docket Control demonstrating that it had a DSC and a TIER equal to or greater than 1.0, within 60 days from the close of each new debt financing under this docket.
7. That UNS file a report with Docket Control, within 60 days from the close of each financing package, describing the transaction and demonstrating that the terms are consistent with those generally available to comparable entities.

Q. Does this conclude your testimony?

A. Yes.

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BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

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 AND REQUEST FOR APPROVAL OF RELATED FINANCING	DOCKET NO. E-04204A-06-0783

DIRECT

TESTIMONY

OF

STEVE TAYLOR

ELECTRIC UTILITY ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 28, 2007

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ENGINEERING REPORT ST-1

EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE
DOCKET NO. E-01773A-04-0528

UNS Electric filed a rate application with the Arizona Corporation Commission ("ACC or Commission") on December 16, 2006. The twelve months ending June 30, 2006, was selected by UNS Electric as its test-year for all rate making revenues, rate based utility plant, and operating expenses. A Quality of Service Assessment was conducted to assure the need for facilities included in rate based utility plant. A Used and Useful Assessment was conducted on plant in service as of June 30, 2006. Construction Work in Progress ("CWIP") in effect as of June 2006 was also included in the rate based utility plant and was similarly reviewed. Additionally, UNS Electric requests inclusion of a post test year adjustment to rate base for a proposed generating station referred to as the Black Mountain Generating Station. This testimony concerns these proposed additions to rate based utility plant.

WITNESS BACKGROUND AND QUALIFICATIONS

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

A. My name is Steve Taylor. I am an Electric Utility Engineer employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background.

A. I graduated from Duke University in 1970 with a Bachelor of Science degree in Electrical Engineering.

Q. Do you hold any special licenses or certificates?

A. I am licensed with the States of Arizona and Maryland as a Professional Engineer - Electrical.

Q. Briefly describe your responsibilities as an Electric Utility Engineer.

A. I joined the Staff as an electric engineer in October, 2006. In my capacity as an Electric Utility Engineer, I have investigated the quality of service provided by two electric utilities in Arizona as part of financing applications before the Commission. I have prepared Commission Utility Staff positions on two line siting cases, the Arizona Public Service ("APS") Pinnacle Peak to TS 9 500/230 kV project and the Salt River Project ("SRP") Desert Basin 230 kV project. I have worked with area utilities in setting up load studies as part of the Commission's Biennial Transmission Assessment ("BTA"). I have worked with APS on preparing a Commission Utility Staff position on a high voltage transformer sharing agreement and sale of two properties.

Q. Please describe other pertinent work experience.

A. I have over 30 years of experience as an engineer and manager in the electric utility industry. I was employed by Potomac Electric in Washington, D.C. and Maryland from 1970 through 2002. During that time I: 1) analyzed and planned transmission and distribution system improvements; 2) managed the design and construction of various transmission and distribution assets 3) managed the operations and maintenance function involving various transmission and distribution assets. Additionally, I was employed by Power Engineers ("Power") in Hailey, Idaho from 2003 through 2006. During that time I was contracted to Texas Utilities in Ft. Worth, Texas to manage on site the various transmission line and substation construction plans generated by Power. This primarily involved the scheduling of construction activities, resolving of design and construction issues, bidding out contracts, resolving contractor payments and assisting remotely located Power staff with design issues on new projects.

Q. Have you previously testified before this Commission?

A. Yes. I have experience testifying before the Commission. I have provided testimony for two transmission line applications for a Certificate of Environmental Compatibility.

PURPOSE AND PREPARATION OF TESTIMONY

Q. What is the purpose of your testimony in this case?

A. I am providing Staff's testimony concerning the quality of service supplied by UNS Electric, a field assessment of used and useful assets, a field assessment of construction work in progress ("CWIP") assets and a brief overview of the proposed Black Mountain Generating Station ("BMGS") project.

Q. How have you prepared for your testimony?

A. I have reviewed information on file, issued data requests to UNS Electric and reviewed those responses, inspected UNS Electric plant facilities and talked with UNS Electric personnel.

Q. When did you inspect UNS Electric's facilities?

A. I inspected various facilities and consulted with UNS Electric personnel as described in Staff's Engineering Report relative to this docket (hereinafter referred to as the "Report") on May 30 through June 1, 2007, in the Tucson area and on June 6 through 9 in the Kingman area. Additionally, I was in Tucson on January 22, 2007, on a matter unrelated to the subject Docket and visited various facilities with UNS Electric personnel, two facilities of which pertain to the subject docket. My findings are in the Report and are attached as Exhibit ST-1.

Q. What UNS Electric personnel have you talked with concerning this docket?

A. I have talked primarily with Mr. Ed Beck, Mr. Sam Ruggell, and Mr. Ricky Robles representing UNS Electric in Santa Cruz County and Mr. Bill Degilio representing UNS Electric in Mohave County. I did have short discussions with several other UNS Electric representatives during the site visits in Santa Cruz County and Mohave County and some others while setting up the site visits and resolving data response questions.

Q. What documentation have you reviewed in preparing your testimony?

A. I have reviewed all rate application material filed by the applicant, numerous responses to Staff data requests and information made available for review during the May and June, 2007 site visits.

Q. Is your testimony herein based upon the aforementioned facility site observations, conclusions drawn from review of available documentation, information gathered by talking with applicant personnel and your educational background and work experience as a utility professional?

A. Yes it is.

QUALITY OF SERVICE ASSESSMENT

Q. How does Staff determine whether or not UNS Electric or any electric utility is providing reliable electric service?

A. Unfortunately, there are no single measures or even groups of measures that can definitively declare a utility is or is not supplying reliable electric service to its customers. The answer to this question has generally been to look at each utility individually, taking into account the unique conditions often found in different parts of the country, the unique conditions that a utility may have to deal with in its service territory, outage measurement systems the utility is using or may be in a position to use, and the utility's general approach and responsiveness to outages. The answer to the question of reliable electric service is based on a professional analysis of all the data available and a conclusion usually qualified with considerations for any unique circumstances that may be part of the utilities' operating circumstances.

Q. Would Staff agree that utilities should be striving for uninterrupted service?

A. Yes, moving toward uninterrupted service is a worthwhile goal for any utility, but the reality is that most utilities on a system wide basis will find this unattainable on a 100 per cent continuous basis. The high cost of constructing electric plant means that utilities must build and improve utility plant facilities with a goal of supplying reliable electric service at a reasonable cost. This reliable electric service at reasonable cost measure is

somewhat subjective and interpreted differently by utilities and customers. An appropriate approach for utilities is to measure what they have with regard to outage histories and then strive for continuous improvement in those measures. The result should be that customers should be the recipient of continually improved electric service and the utility can appropriately and reasonably manage the cost of needed plant improvements.

Q. If there is no single measure of reliability and no precise goal, then what exactly does Staff look at to reach a conclusion on reliability of electric service?

A. Staff looks at all the information that is available and then reasonably weighs all the individual conclusions to reach an overall conclusion. There are numerous factors that should be looked at in a utility like UNS Electric. A complete analysis of each factor is included in the Report attached as Exhibit ST-1 and each factor is briefly described below.

Reliability indices for U. S. utilities are available on a limited basis and it is useful to compare where one stands as a utility with respect to these established metrics. UNS Electric showed some favorable comparisons to some of the available reliability metrics and some lower performance comparisons to others. Summer storm activity appeared to be a consideration in the lower performance comparisons.

A review of worst performing feeders was conducted to see how UNS Electric was responding to areas where customers were being most impacted by outages. UNS Electric personnel were cognizant of these problem areas and generally seemed to be taking proactive steps to minimize future problems.

A trend analysis was considered for review as a tool to determine if service is improving, degrading or remaining constant. Unfortunately, there was insufficient data prior to 2004

so this analysis was not performed. It will however, be a useful tool in future years to track changes in reliability metrics.

Quality of service complaints that were received by the Commission regarding UNS Electric service reliability were reviewed for the years 2004 through 2007. A total of 32 complaints were examined with most complaints of a general nature related to power outages and as described in the Report attached as Exhibit ST-1. No unusual patterns or issues were noted in the complaints on file with the Commission.

A review of the UNS Electric transmission system was conducted with primary reliance on the Biennial Transmission Assessment ("BTA"). There are several identified projects and activities noted in the BTA affecting UNS Electric; however, this information is well known to UNS Electric and various activities are underway to address these issues.

Load growth on the UNS Electric system was reviewed as the growth of an electric system can impact reliability. UNS Electric is looking at very high growth rates especially in some parts of the Mohave service territory which needs to be considered in conjunction with the capital construction program.

The five year capital construction program was reviewed and the expenditures planned seemed commensurate with a rapidly growing service territory. It should be noted that Staff is not implying any specific treatment or recommendation for rate base or rate making purposes in any UNS Electric rate filings.

Q. In consideration of all the factors then what is Staff's conclusion on UNS Electric supplying reliable electric service?

A. Staff believes UNS Electric is supplying its customers with reliable electric service.

Q. Are there any considerations that should be noted as part of Staff's conclusion that UNS Electric is supplying reliable electric service?

A. There is clearly room for improvement in reliability of any utility electric system. Staff suggests to UNS Electric that continued improvement of its outage measurement systems, and a focus on improving outage metrics especially with regard to those associated with the "Worst Performing Feeders", will serve its customers well and allow UNS Electric the most effective use of its capital budget associated with outage improvement.

USED AND USEFUL ASSESSMENT

Q. How did Staff decide which projects should be part of a Used and Useful Assessment?

A. The initial approach for this assessment was to look at a representative group of projects placed in service and considered Used and Useful during the rate case test year ending June 30, 2006. The data response by UNS Electric to this issue produced a listing too short to provide a representative sampling, so the period for review was increased to the 36 month period ending June 30, 2006. This produced a suitable listing of projects to choose from and ten projects were selected for review representing different cost classes (transmission, production, etc.) and equally divided between the Santa Cruz and Mohave service territories.

Q. What did Staff look for in making a Used and Useful determination?

A. The primary objective in this assessment was to determine that the asset reviewed had verifiable documentation available demonstrating that the asset was placed in service no later than the end of the test year and it was performing the function for which it was intended. Additionally, as part of a prudent and reasonable determination for each asset, available documentation was reviewed to determine the asset was warranted and the cost of the asset was reasonable and had appropriate management review.

Q. Could all this have been accomplished through reviewing responses to data request?

A. No, a field review is required to confirm the function of the asset is being accomplished, along with reviewing data responses. In addition, a general discussion of each asset was accomplished at UNS Electric offices just prior to the May and June, 2007 site visits to Tucson and Kingman.

Q. What were the results of Staff's review of the ten projects selected for the Assessment?

A. All projects were determined to be Used and Useful no later than June 30, 2006. A detailed summary of the findings on each project are in the Report and are attached as Exhibit ST-1.

Q. Are there any special considerations or findings in any of the project reviews in the Used and Useful Assessment?

A. Yes. One project, the Tubac Golf Resort Overhead to Underground conversion with a cost of $236,873.96, had the appearance of a project that might be significantly reimbursed by the customer and, if so, then not eligible for inclusion in rate base in the portion reimbursed. UNS Electric was unable to provide sufficient documentation at the

time of this testimony to make a definitive determination on the reimbursable portion of this project and resultant rate base inclusion, if any. Staff recommends that a final determination be made on the treatment of this project after UNS Electric has supplied the necessary documentation.

Q. Were there any other findings of note?

A. Staff generally found all facilities inspected in the field to be up to National Electric Safety Code Standards and built in accordance with good utility practices. Staff did note two issues at London Bridge Substation in the Report with regard to security fencing and oil containment that warranted further review by UNS Electric.

CWIP ASSESSMENT

Q. How did Staff decide which projects should be part of a CWIP Assessment?

A. The approach for this assessment was to look at a representative group of projects that were carried as CWIP by UNS Electric and identified as Net CWIP June 2006. The five identified projects totaled approximately $4.1 million in CWIP as of June 2006, and were selected based on obtaining a representative sampling of cost classes (transmission, production, etc.) in both the Santa Cruz and Mohave service territories. Additionally, as the list of CWIP projects provided by UNS Electric was extensive, the selected projects were the higher accumulated cost projects to adequately represent the $10.8 million net CWIP of June 2006 included in the rate case application.

Q. What did Staff look for in making a CWIP determination?

A. Staff's primary objective in this assessment was to determine that the asset reviewed had verifiable documentation available that it was placed in service at a specific date after June 30, 2006 or it was continuing as a CWIP project. Additionally, as part of a prudent and

reasonable determination for each asset, available documentation was reviewed to determine the asset was warranted and the cost of the asset was reasonable and had appropriate management review.

Q. Could all this have been accomplished through reviewing responses to data requests?

A. No, a field review is required, to confirm the function of the asset is being accomplished, or will be accomplished at some future time, along with reviewing data responses. In addition, a general discussion of each asset was accomplished at UNS Electric offices just prior to the May and June, 2007 site visits to Tucson and Kingman.

Q. What were the results of Staff's review of the five projects selected for the CWIP Assessment?

A. All projects were determined to be appropriately included in CWIP as of June, 2006. A detailed summary of the findings on each project is in the Report and is attached as Exhibit ST-1.

Q. Are there any special considerations or findings in any of the project reviews in the CWIP Assessment?

A. Yes. One project, the Rhodes Homes 21 kV supply with a CWIP inclusion of $442,254.92 was determined to be in service May 26, 2006 and therefore could reasonably qualify for Used and Useful treatment. It was noted in the review of this project with the UNS Electric representative that the cost of the project was advanced 100 per cent by the customer and the construction amount was then subject to repayment to the customer by UNS Electric when certain load conditions (described in an Agreement between parties) on the new supply line developed.

Q. Were there any other findings of note?

A. Yes, all facilities inspected in the field associated with the CWIP review were found to be up to National Electric Safety Code Standards and built in accordance with good utility practices.

BLACK MOUNTAIN GENERATING STATION ("BMGS") REVIEW

Q. Why is there a review of the BMGS in your Report?

A. BMGS is a proposed 90 megawatt facility in Mohave County for which $60 million to $65 million has been included in the rate base application for procurement by UNS Electric. UNS Electric has provided pre filed testimony with regard to BMGS. It was expedient for Staff to conduct a site review of this project while in the area June 6 and 7, 2007 in the course of the other field reviews described earlier in this testimony. The primary objective was to verify what stage of construction BMGS was in.

Q. What observations did Staff make about the BMGS?

A. Before the field review, Staff inquired about the expenditures to date for BMGS. Staff was advised that approximately $41 million has been spent to date for the two turbines, engineering, station materials and gas line construction. Staff reviewed the field site for the BMGS on June 6, 2007 with a UNS Electric representative and observed the land at issue is "open desert" south of Kingman and a few miles from the existing Griffith Power Plant. There is a large gas line (obviously for the proposed plant) being constructed along the frontage and through a portion of the property and a 69 kV wood pole line exists on the frontage road for the site. No other utility infrastructure (or structures of any kind) was observed on the site. A more complete summary of observation on the BMGS are in the Report and are attached as Exhibit ST-1.

Q. What conclusions did Staff make about the BMGS?

A. Staff concludes only that the BMGS site on June 6, 2007 near the Griffith Power Plant showed active construction of a gas line project and the site was readily accessible to an existing 69 kV line on the site's road frontage. No other construction activities, including equipment storage of any kind, were noted on the site.

SUMMARY OF TESTIMONY CONCLUSIONS

Q. Please summarize the conclusions of your testimony.

A. Staff has four separate conclusions. First, UNS Electric is supplying its customers with reliable electric service. Staff offered UNS Electric recommendations on outage measurement initiatives (improved outage measurement in Mohave County and a focus on identifying and improving performance of "Worst Performing Feeders" in both the Mohave and Santa Cruz territories). Second, all projects in the Used and Useful review were determined to be Used and Useful no later than the end of the test year which was June 30, 2006. One project, the Tubac Golf overhead to underground conversion, appeared to possibly have a significant customer contribution which needs to be resolved before inclusion of the project in rate base. Two field observations during the review are also noted at the London Bridge substation with regard to security fencing and oil containment for any appropriate UNS Electric action. Third, all projects in the CWIP review were determined to be appropriately classified as Net CWIP June 2006 although this is not a recommendation for or against inclusion of any CWIP in the rate base application. One CWIP project, the 21 kV supply to Rhodes Homes well pumps, actually qualified for Used and Useful treatment since the 21 kV line was determined used and useful on May 26, 2006 which was prior to the end of the test year. There is, however, a customer advance for this project that must be resolved in either a CWIP or Used and Useful treatment. Fourth, a review of the field conditions at the proposed BMGS project

determined the site work for this project is in the initial stage with gas line construction in progress and an existing 69 kV line noted on the frontage road of the site. No other construction materials or activities were observed on the site.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MEMORANDUM

TO: Docket Control

FROM: Ernest G. Johnson
Director
Utilities Division

DATE: June 15, 2007

RE: ENGINEERING REPORT ANALYZING QUALITY OF SERVICE MATTERS, USED AND USEFUL REVIEW AND CONSTRUCTION WORK IN PROGRESS REVIEW RELATED TO THE UNS ELECTRIC COMPANY RATE CASE APPLICATION, DOCKET NO. E-04204A-06-0783.

Attached is an engineering report documenting a Utilities Division quality of service assessment for the calendar years 2004 through 2006, and a Used and Useful Review and Construction Work in Progress ("CWIP") Review of UNS Electric for the three year period ending June 30, 2006. It is intended for use as a Commission Staff reference document in the pending UNS Electric rate case, Docket No. E-04204A-06-0783.

Engineering finds no reason to recommend consideration of quality of service mitigation measures as part of the pending UNS Electric rate case based upon the results of the assessment; however, we do offer suggestions on future reliability initiatives that would, Staff believes, well serve UNS Electric and its customers.

Engineering further finds no reason to exclude any of the ten projects in the Used and Useful Review from rate base inclusion with the possible exception of the Tubac Golf Resort Overhead to Underground conversion which may have a significant customer contribution component. UNS Electric was not able to provide sufficient documentation at the time of this report to make a definitive determination on this project. A few suggestions regarding substation particulars on other projects were included in the report for necessary follow up action by UNS Electric.

Engineering further finds all five projects in the CWIP review were in construction at the time of the CWIP accounting in June 2006 with three completed at the time of this Report and two projects continuing. One of the completed projects, the Rhodes Homes 21 kV supply for water pumps was in service just prior to the end of the test year and qualifies for Used and Useful treatment with consideration for a 100% customer advance. Engineering again notes, as in the Report, that the CWIP review is not a recommendation for or against including these projects associated CWIP cost in rate base.

Additionally, for general information, Engineering was in a position to make a cursory review of the proposed Black Mountain Generating Station project (scheduled for service in 2008) which was in the vicinity of various site visits in Mohave County. The Report includes a brief review of those findings.

SHT:tdp

Originator: Steve Taylor

Attachment: Original and Thirteen Copies

ENGINEERING REPORT
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

UNS ELECTRIC, INC.
RATE CASE
DOCKET NO. E-04204A-06-0783

STAFF'S ASSESSMENT OF:

QUALITY OF SERVICE

USED AND USEFUL CAPITAL ASSETS

CONSTRUCTION WORK IN PROGRESS CAPITAL ASSETS

BLACK MOUNTAIN GENERATING STATION

JUNE 28, 2007

STAFF ACKNOWLEDGMENT

This Engineering Report was prepared by the Arizona Corporation Commission Utilities Division ("Utilities Division") for use in the UNS Electric, Inc. ("UNS Electric") rate case, Docket No. E-04204A-06-0783. It provides an analysis of the quality of service provided by UNS Electric for calendar years 2004 through 2006. It also provides a used and useful assessment regarding capital improvements made in the thirty six months prior to June 30, 2006 (end of rate case test year). Additionally, it addresses construction work in progress ("CWIP") that has been included in rate base in the Application. Observations of the Black Mountain Generating Station and related discussion with UNS Electric are also included for general information. The report documents an engineering assessment by Steve Taylor of the Utilities Division regarding these three primary matters and the one observational issue.

Steve Taylor actively monitors quality of service matters for all Arizona utilities on an ongoing basis. His quality of service assessment of UNS Electric is based upon a review and analysis of the company's response to data requests concerning quality of service matters.

A Used and Useful assessment requires a physical survey of selected new and improved facilities to assure completion of construction, validation that equipment is fully operational, and that the facilities meet National Electric Safety Code ("NESC") requirements per Arizona Administrative Code R14-2-208. Mr. Taylor has extensive industry experience regarding such investigations. His used and useful assessment of UNS Electric's capital improvements is based upon inspection of a sampling of UNS Electric facilities and review and analysis of the company's response to data requests concerning its capital improvements.

A Construction Work in Progress ("CWIP") assessment requires a review of newly completed (since the end of the test year) and on going capital projects that were included in the rate base of the Application and followed by a selected physical survey of the facilities. Mr. Taylor has extensive industry experience regarding such investigations. His CWIP assessment of UNS Electric's capital improvements is based upon inspection of a sampling of UNS Electric's facilities and review and analysis of the company's response to data requests concerning its capital improvements.

Steve Taylor
Electric Utility Staff

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EXHIBITS

Used and Useful Review Projects-May 7, 2007 ..... **Exhibit 1**

Checklist for ACC Santa Cruz Project Review ..... **Exhibit 2**

Checklist for ACC3 Mohave Project Review ..... **Exhibit 3**

CWIP Review Projects-May 7, 2007 ..... **Exhibit 4**

I. PURPOSE OF ENGINEERING REPORT

This engineering report serves a three fold purpose. It documents a quality of service assessment of UNS Electric performed by Utilities Division Engineering Staff ("Staff"). Secondly, it provides a Used and Useful assessment of UNS Electric's capital improvements for the thirty six months ending June 30, 2006 (end of the test year) performed by Staff. Thirdly, it provides a Construction Work in Progress ("CWIP") assessment of projects that were included with rate base in UNS Electric's Application also performed by Staff. As a peripheral matter, in the process of conducting office and site reviews, it was expedient to conduct a preliminary review of the proposed Black Mountain Generating Station and these observations are included in the report also. The report is filed with the Arizona Corporation Commission ("Commission") in support of the Commission's evidentiary record for the UNS Electric's rate case, Docket No. E-04204A-06-0783.

II. QUALITY OF SERVICE ASSESSMENT

A. FRAMEWORK

Staff's quality of service assessment of UNS Electric covers the calendar years 2004 through 2006. It is based upon information collected via data requests of UNS Electric and an associated review of that information in comparison to an Institute of Electrical and Electronic Engineers ("IEEE") reliability measurement survey performed in 1995 and a specific review of distribution feeders with the highest UNS Electric outage rates. Additionally, this assessment considers findings of consumer complaints regarding quality of service filed with the Commission's Consumer Services Section. A review of the transmission system in the Applicant's service area is also considered utilizing the 2006 Biennial Transmission Assessment ("BTA") which was performed in accordance with Arizona Revised Statute §40-360.02.G. Forward projections of expected future reliability are then offered in consideration of the aforementioned analyses plus growth rates and projected capital construction. The Assessment closes with Conclusions based on the available information.

B. DISTRIBUTION SYSTEM

Distribution reliability is a subjective measure and must generally take into account the available outage measurement systems, comparisons to other accepted industry indices, comparison to internal company indices for trend analysis, identification of problem areas and corrective action. This information is then considered along with other factors described in the subsequent items of the Quality of Service Assessment to reach an overall Quality of Service Conclusion (Item II.F).

B.1 RELIABILITY INDICES

The Commission has adopted a North American Reliability Council ("NERC") definition of reliability for Staff's use in the Biennial Transmission Assessment. Reliability is comprised

of two components: adequacy and security. Adequacy is the ability of an electric system to supply the aggregate electrical demand and energy requirements of its customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. On the other hand, security is the ability of an electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. These components of reliability are subjective, not easily measured and leave much to interpretation.

Many utilities use numerical indices as a measure of an average customer's distribution service reliability. Such reliability indices are typically computed on an annual basis. A utility may then set reliability targets based upon benchmarked data from its own system. The IEEE has adopted a standard definition for several reliability indices for electric distribution systems and established a national benchmark database via a 1995 IEEE survey of the electric utility industry. The most commonly used reliability indices are System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI"), and Customer Average Interruption Duration Index ("CAIDI"). All three reliability indices are defined in IEEE Standard 13-2003, IEEE Guide for Electric Power Distribution Reliability Indices.

SAIFI is the average number of interruptions experienced by customers per year. SAIDI is the average number of interruption minutes experienced by customers per year. CAIDI is the average duration of interruptions. MAIFI is the average number of momentary interruptions experienced by customers per year where a momentary interruption is generally defined as 5 minutes or less and is associated with the normal function of electric system restorative devices such as circuit breakers and reclosures. The MAIFI statistic is a lesser used measure in the industry as it is not indicative of longer outages; however, it does measure an "annoyance factor" with customers when short interruptions (5 minutes or less) are excessive, thereby causing the frequent resetting of many electronic devices in the home or business. Per Rural Utilities Service ("RUS") Bulletin 161-5, the RUS considers a SAIDI of five hours (300 minutes) or more per consumer as unacceptable except under very unusual circumstances. The IEEE 1995 Survey established typical reliability index values for the electric utilities in the United States as displayed in the following table.

Table 1
Typical Reliability Index Values for US Utilities

Average	SAIFI	SAIDI	CAIDI	MAIFI
Top quartile	0.90	54	55	1.5
Second quartile	1.10	90	76	5.4
Average	1.26	117	88	6.6
Third quartile	1.45	138	108	11.1
Bottom quartile	3.90	423	197	13.7

Staff proposes to compare in Table 2 the actual UNS Electric distribution system reliability indices to the typical reliability indices contained in Table 1. The UNS Electric data utilized for this comparison is the year end metric for each of the last three years reliability indexes for UNS

Electric in each of the 4 categories noted in Table 1 and itemized by Santa Cruz County, Mohave County and UNS Electric's total territory. These measures are an aggregate of all measures made on a UNS Electric system wide basis in total for UNS Electric and in part for UNS Electric's Mohave and Santa Cruz Counties. Although there are obviously some variations in the measures in different parts of UNS Electric's 7,250 square mile Mohave service territory and 677 square mile Santa Cruz territory due to a variety of factors such as customer density, geography and weather patterns for example, the aggregate measures are a reasonable indicator of overall reliability.

Additionally, these UNS Electric measures in Table 2 include "Major Event Days" generally associated with major storms and scheduled outages generally associated with maintenance or construction work activities pre arranged to minimize customer impact. This is necessary because UNS Electric does not collect outage data with a differentiation between types of outages so their data is all inclusive. This puts UNS Electric at a disadvantage in the comparison to the IEEE 1995 data which normally would have been done both with and without "Major Event Days" and scheduled outages. This would be an appropriate accommodation in the UNS Electric comparison, in Staff's opinion, due to the nature of data collection in the 1995 IEEE Survey not being all inclusive in all cases. Nonetheless, this comparison of UNS Electric data to IEEE data can still be made with some explanation to address this anomaly. On this basis, Staff can make an objective assessment of the quality of service being provided to UNS Electric's distribution system customers.

The results of this comparison are summarized in Table 2 below with the UNS Electric individual year and service territory metrics positioned in the corresponding IEEE quartile from Table 1. The results show that UNS Electric's reliability indexes range from top quartile to bottom quartile performances in the four metrics.

Table 2

UNS Electric Reliability Index Values Compared to Typical for US Utilities

Ranking	SAIFI	SAIDI	CAIDI	MAIFI
Top quartile				SC '05 (0.7) SC '06 (1.2)
Second quartile	MO '04 (1.01) SC '04 (1.07) UN '04 (1.03) MO '05 (1.08)	MO '04 (76) SC '04 (68) UN '04 (75) MO '05 (89)	MO '04 (76) SC '04 (64) UN '04 (73)	MO '05 (4.5) UN '05 (3.7) MO '06 (5.0) UN '06 (4.2)
Third quartile			MO '05(82) SC '05 (106) UN '05 (93) MO '06 (97) SC '06 (87) UN '06 (96)	
Bottom quartile	SC '05 (3.14) UN '05 (1.52) MO '06 (2.83) SC '06 (1.76) UN '06 (2.58)	SC '05 (334) UN '05 (142) MO '06 (275) SC '06 (153) UN '06 (245)		

Note: Designations are SC for Santa Cruz County, MO for Mohave County and UN for the combined Santa Cruz and Mohave counties each followed by their corresponding metric.

Under normal circumstance in which utilities would have removed most of their severe storm and scheduled outage impact from their metrics (for which UNS Electric is presently not programmed to do), Staff would expect to see generally second quartile performance for most of the metrics with some first quartile performance. In this analysis for UNS Electric, approximately half the metrics meet this expectation. The bottom quartile metrics are of some concern and must be looked at in conjunction with explanations of the data and the overall conclusions for the Quality of Service Assessment in Section II.F of this Staff Report.

UNS Electric has noted in their data submittals that there were 9 months in Mohave County and 3 months in Santa Cruz County over the 3 year analysis period in which customer outage minutes exceeded 1,000,000 minutes due primarily to summer monsoon activity. It is reasonable to conclude that a significant contributing factor to the bottom quartile performance is the impact of severe summer weather on UNS Electric's electric system with rural exposure. Additionally, it is noteworthy that the CAIDI metrics (SAIDI divided by SAIFI) fall into the higher third quartile and as this is a truer measure, in Staff's opinion, of how long someone affected by an outage will be out, it is a measure of significance. Also the MAIFI metrics are consistently good showing first and second quartile performance, although some of this may be

attributable to UNS Electric's shorter measurement of a momentary outage (3 minutes versus the IEEE standard of 5 minutes).

B.2 WORST PERFORMING FEEDERS

Reliability indices on a system aggregate basis are useful for determining overall reliability; however, an aggregate review may tend to mask more severe problems in a particular area. For this reason Staff reviewed the history of the worst performing distribution feeders in each of the Mohave and Santa Cruz territories to determine if there were any particular service issues that required further attention. By definition, there will always be distribution feeders in the worst performing category since the measure is relative to all other distribution feeders of that utility in the study area regardless of their performance level. The intent of the review is to look at the impact to customers in any single year, the repeat impact if any feeder remains a worst performing feeder in different years, and the corrective measures employed by the utility.

Staff reviewed the data submitted by UNS Electric for the three worst performing feeders in Mohave County and makes the following observations:

1. Three years data was submitted (2004 through 2006) and no single feeder appeared in more than a single year.

2. The Golden Valley area appeared in both 2004 and 2005 but on separate feeders. No other particular geographic pattern was observed in the outages.

3. No action (other than restoration) was taken on most feeders over the three year period although underground cable was replaced and temporary facilities removed in two cases.

4. Using a modified definition of CAIDI (total customer minutes divided by customers affected) to determine average customer outage times, the performance ranges from 62 minutes per customer per year to 333 minutes per customer per year. The 62 minutes per customer per year equates to second quartile performance relative to the IEEE standard and the 333 would equate to fourth quartile. Comparison of individual feeder metrics to the IEEE standard in this manner is not standard protocol however it does indicate where more review might be appropriate. The 62 minutes per customer per year is reasonable performance and the 333 minutes per customer per year and measures of this magnitude require consideration with other factors.

5. Of the nine feeders reviewed over three years, five had outage times averaging less than 100 minutes per customer per year and four had outage times averaging more than 100 minutes per customer per year. An outage rate of 100 minutes per customer per year equates to third quartile CAIDI performance in the normal definition of IEEE performance and would generally be considered an acceptable level of performance.

6. Outage performance was not correlated to any particular storm activity; however, Staff believes storms were a significant factor in these outages based on data supplied by UNS Electric and addressed in the final paragraph of Section II.B.1 herein.

Staff similarly reviewed the data submitted by UNS Electric for the three worst performing feeders in Santa Cruz County and makes the following observations:

1. Two years data was submitted (2005 and 2006). One feeder (C-8203 serving N. Pendleton) appeared in both years.

2. No action (other than restoration) was taken on all feeders over the two year period.

3. Using a modified definition of CAIDI (total customer minutes divided by customers affected) to determine average customer outage times, the performance ranges from 35 minutes per customer per year to 141 minutes per customer per year. The 35 minutes per customer per year equates to first quartile performance relative to the IEEE standard and the 141 would equate to fourth quartile. Comparison of individual feeder metrics to the IEEE standard in this manner is not standard protocol however it does indicate where more review might be appropriate. The 35 minutes per customer per year is reasonable performance and the 141 minutes per customer per year and measures of this magnitude require consideration with other factors.

4. Of the five feeders reviewed over two years, two had outage times averaging less than 100 minutes per customer per year and two had outage times averaging more than 100 minutes per customer per year and one had an outage time close to 100 minutes per customer per year. An outage rate of 100 minutes per customer per year equates to third quartile CAIDI performance in the normal definition of IEEE performance and would generally be considered an acceptable level of performance.

5. Outage performance was not correlated to any particular storm activity; however, Staff believes storms were a significant factor in these outages based on data supplied by UNS Electric and addressed in the final paragraph of Section II.B.1 herein.

In addition to the data review, Staff determined that four feeders selected from the worst performing list warranted a closer field review to evaluate field conditions and planned or otherwise possible improvements. The four feeders were selected based on those with greater customer impact and also characterization as a worst performing feeder in more than a single year. The feeders selected were inspected with Staff and UNS Electric personnel on May 31, 2007 in Santa Cruz County and on June 7, 2007 in Mohave County. A summary of the findings is provided as follows:

1. Canez Feeder C-8203 serving N. Pendleton Dr (Santa Cruz County) is a very long (approximately 100 miles) 13 kV distribution feeder serving residential and light commercial load in a partially mountainous area between Tucson and Nogales and east of

Interstate 19. Staff inspected portions of the feeder on May 31, 2007 with UNS Electric personnel and observed that problems were being regularly addressed with the addition of lightening arresters in selected locations, replacement of wood poles with steel poles in unstable soil areas along the Santa Cruz river, cross arm installation at selected locations to increase phase spacing, and fairly aggressive and recent tree trimming in the high vegetation areas close to the Santa Cruz river. Additional action being considered includes transferring some parts of this feeder to other feeders to reduce the length of line exposed and adding field reclosures (one presently exists) to isolate areas that have faulted in lieu of larger segments of the feeder. Since the area has topography which tends to make it subject to summer thunderstorms with resultant lightening and wind impacts and the overhead line exposure is high (about 50 percent of the 100 mile line is overhead), the feeder will likely remain as one which will require continued attention in the future. Staff was concerned that voltage degradation might be a problem at some locations on this feeder due to its long length; however, UNS Electric advised that maintaining the proper voltage has not been a problem. Staff believes UNS Electric has taken the appropriate steps to minimize customer outages as evidenced by the work of the last few years and is prepared to continue improvements of this feeder.

2. Mohave Feeder 8008 serving Aqua Fria and Golden Valley (Mohave County) is a short (less than five miles) 13 kV overhead distribution feeder serving residential load in a generally flat valley area between Kingman and Bullhead City. The topography of the area makes the feeder subject to lightening impacts during summer thunderstorms. The wind impact from these summer storms appears minor as there is minimal tall vegetation in the area that could be blown into the feeder although blowing debris presents some risk. The conductor is a relatively small Number 2 aluminum conductor steel reinforced ("ACSR") which is targeted for replacement with larger conductor probably in 2008 or 2009. A substantial portion of the feeder is built underneath a 69 kV feeder on a common pole line thereby protecting the under built 13 kV from lightening strikes and resultant outages. The rebuilding of the Number 2 ACSR line (comprising the bulk of the feeder) will provide additional lightening protection for the feeder due to the new construction standard requiring approximately 5 lightening arresters per pole mile of line thereby reducing the likelihood of any lightening induced outages on the 13 kV portion of the feeder. Staff believes this feeder as in place today presents a low risk of excessive outages affecting customers. Additionally, UNS Electric will be taking appropriate steps to further minimize customer outages on this feeder with the replacement of the feeder with larger conductor and associated lightening protection.

3. Mohave Feeder 8016 serving Aqua Fria and Golden Valley (Mohave County) is a relatively short (less than ten miles) 21 kV overhead distribution feeder with some underground serving residential load and some light commercial load in a generally flat valley area between Kingman and Bullhead City. The topography of the area is common to Mohave Feeder 8008 described above and makes the feeder subject to lightening impacts during summer thunderstorms. The wind impact from these summer storms appears minor as there is minimal tall vegetation in the area that could be blown into the

feeder although blowing debris presents some risk. A substantial portion of the feeder was rebuilt approximately six years ago however the standard at that time did not call for lightening arrester protection along the main feeder trunk except at transformers and other similar equipment connections. Staff believes this feeder as in place today presents a low risk of excessive outages affecting customers although outages could likely be most attributable to summer storm and lightening activity. Staff suggests that further monitoring of the outage performance of this feeder be conducted and if a correlation is made between excessive outage rates and area lightening activity, then consideration be given to the installation of additional lightening arresters along the feeder.

4. Mohave Feeder 6026 serving a portion of the Lake Havasu area out of North Havasu Substation is a moderate length (approximately 20 miles) 13 kV overhead distribution feeder serving residential load and some light commercial load in a hilly area just east of Lake Havasu. (Mohave County). The feeder is frequently constructed along the rear lot line of homes (instead of the more common street frontage construction) which may impede utility access and thereby increase some restoration times. The line construction employs lightening arresters at transformers and other similar equipment connections. The topography of the area makes the feeder subject to lightening impacts during summer thunderstorms. The wind impact from these summer storms appears minor as there is minimal tall vegetation in the area that could be blown into the feeder although blowing debris presents some risk. Staff believes this feeder as in place today presents a low risk of excessive outages affecting customers although outages could likely be most attributable to summer storm and lightening activity. Staff suggests that further monitoring of the outage performance of this feeder be conducted and if a correlation is made between excessive outage rates and area lightening activity, then consideration be given to the installation of additional lightening arresters along the feeder.

Staff finds no particular patterns or circumstances of concern in the outage statistics for UNS Electric's worst performing feeders based on the information available. Ordinarily, Staff would prefer to analyze a minimum of five recent consecutive years' data to identify repeating worst performing feeders and areas repeatedly affected. UNS Electric does not have any IEEE type data prior to 2004 since the Arizona assets of Citizens were not acquired until that time. The one feeder in the data supplied that does have more than one year in the worst performance category is C-8203 in Santa Cruz County however the corresponding modified CAIDI measurement is not unreasonable (141 in 2005 and 125 in 2006) and the number of affected customers is relatively low (approximately 200).

Staff did note that UNS Electric utilizes their Outage Management System ("OMS") to collect outage statistics in Santa Cruz County. The Santa Cruz system is capable, in Staff's opinion, of collecting and reporting data in a variety of ways with varying amounts of manual interaction. Staff believes it would benefit UNS Electric and their customers to begin collecting data annually in Santa Cruz County to determine the worst performing feeders (a minimum of three identified per year) for Santa Cruz County using a minutes (or hours) per customer affected per year measure (similar to UNS Electric's May 4, 2007 data response number six). This data

collection could, Staff suggests, be modeled using reasonable assumptions to minimize any additional manual effort and still meet the goal of identifying feeders with the most adverse impact on customers. This type of review, in Staff's opinion, would allow UNS Electric to readily determine which feeders are most adversely impacting customer service and then allow UNS Electric Santa Cruz County to better focus their efforts on appropriate upgrades to those feeders.

Staff further notes that UNS Electric utilizes a manual system to collect outage statistics in Mohave County. UNS Electric Mohave County has a Work Management System and a partially developed Geographic Information System with future plans to employ an Outage Management Module as part of the Work Management System in the next few years. Although UNS Electric Mohave County does not have the present ability to collect outage data in the same manner as UNS Electric Santa Cruz County, Staff believes it would be beneficial to customers for UNS Electric Mohave County to similarly adopt a worst performing feeder review as described above for Santa Cruz County when sufficient tools are available to reasonably collect and analyze outage data.

B.3 TREND ANALYSIS

One useful tool for determining reliability is a comparative review of present reliability metrics in relation to past years metrics to determine if the overall reliability is improving, degrading or remaining constant. From that review, it is reasonable to project future reliability with consideration for other growth and capital investment plans.

Staff ordinarily expects to perform this type of analysis if data is available to do so, however, in this case, the data is not available. UNS Electric does not have any IEEE type data prior to 2004 since the Arizona assets of Citizens were not acquired until that time. Additionally, UNS Electric does not separately measure Major Event Days, so their data in the indices is all inclusive. A comparison using only the three years of available data is not constructive in this case. There is no way of differentiating severe storm occurrences from more routine outages and the trend analysis with and without Major Event Days cannot be performed. Additionally, three years data is only marginally sufficient to perform a meaningful trend analysis presuming all other data considerations are met.

C. QUALITY OF SERVICE COMPLAINTS

The Commission regularly receives telephone calls from utility customers who wish to voice their concern (or approval) on a variety of utility issues. These calls are logged in and referrals made to the appropriate utility for response to the customer on the particular issue cited by the customer. The Service Interruption category is one of the categories used to define the type of call received. Although the lack of or low instance of complaints in itself is not a definitive measure of acceptable reliability, a review of complaints when conducted in conjunction with other analyses (such as those included in this assessment) can weigh in the overall assessment conclusion.

Staff has reviewed the logged calls received by the Commission with regard to UNS Electric for the years 2004 through 2007 to date and with the Service Interruption identifier. The calls are summarized as follows:

1. Calendar Year 2004—No complaints received.

2. Calendar Year 2005—A total of 9 complaints received approximately evenly divided between Mohave and Santa Cruz Counties. Complaints were of a general nature (inability to contact UNS Electric promptly, longer outage or more frequent outages than expected, property damage, UNS Electric's response regarding restoration time inadequate). Complaints were received throughout the year with no particular geographic pattern observed. All complaints were addressed by UNS Electric and considered closed by the ACC.

3. Calendar Year 2006—A total of 22 complaints received approximately evenly divided between Mohave and Santa Cruz Counties. Complaints were of a general nature (inability to contact UNS Electric promptly, longer outage than expected, property damage, inability to determine time to make repairs). Complaints were received throughout the year with no particular geographic pattern observed. All complaints addressed by UNS Electric and considered closed by the ACC.

4. Calendar Year 2007—Staff notes only one complaint received at the time of this report with characteristics similar to complaints previously noted.

Staff finds no particular patterns or circumstances of concern in the complaints received by the ACC for the years 2004 through 2007 to date.

D. Transmission

The Commission performs a biennial transmission system assessment in accordance with Arizona Revised Statute §40-360.02.G. The latest assessment, the 2006 Biennial Transmission Assessment ("BTA") was approved by the Commission in March 2007 and evaluates the condition of the overall Arizona transmission system and addresses concerns or accomplishments in specific areas. The Assessment concludes that "In general, the existing and proposed Arizona transmission system meets the load serving requirements of the state in a reliable manner". Staff believes this overall Arizona conclusion is an important element of service reliability for all Arizona utilities; however it is appropriate to also consider any particular findings germane to UNS Electric in the BTA and additionally any other issues beyond the BTA that may be a consideration in assessing the UNS Electric transmission system.

Staff notes in the BTA that Reliability Must Run ("RMR") conditions in the Mohave and Santa Cruz areas supplied by UNS Electric require further analysis and possible action to maintain reliability. When an area must run its own generation due to transmission import constraints, the area is determined to be an RMR area. This is not necessarily undesirable as the

cost of running area generation may be less than the cost of building new transmission. Nonetheless, utilities serving both the Mohave and Santa Cruz areas need to further review this matter so that a long term solution, if necessary, can be implemented. This conclusion is not unlike similar conclusions in year's past and resultant ACC directives to utilities in other areas such as Phoenix where RMR conditions were identified in the 2004 BTA and addressed through system planning analysis and resultant construction plans. The 2006 BTA process has identified this problem in the UNS Electric service territories (as it has done in other Arizona areas in earlier BTAs) and consequently the ACC has directed UNS Electric to perform the necessary RMR studies in conjunction with other associated parties as part of the upcoming 2008 BTA process.

Staff also notes from the BTA that the UNS Electric's plan to improve reliability for the Santa Cruz territory is to construct a second transmission line in the Nogales area from the proposed Gateway substation to the existing Valencia Substation to introduce redundancy of supply and thereby improve reliability. Additionally there are long term improvements for the Santa Cruz transmission system noted in UNS Electric's Ten Year Plan, particularly a new 138 kV circuit between Valencia Substation and Sonoita Substation and upgrade of the Valencia to Vail line from 115 kV to 138 kV.

From a power production and transmission perspective, it is important to consider that UNS Electric is largely dependent on others through contract to provide power and transmit that power to certain locations where it is then picked up on the UNS Electric transmission system. UNS Electric presently meets its power requirements through a Power Supply Agreement with Pinnacle West. Western Area Power Authority is utilized at many of the supply points to transmit power to a location where UNS Electric can tie in their transmission system. This approach to supplying and transmitting power is dependent on the protection and assurances contained in the associated contract conditions. Staff does not foresee any inherent reliability problems in this approach.

E. FORWARD PROJECTIONS

A Quality of Service Assessment is made at a particular point in time, the end of 2006 in this case. Generally however, it is appropriate to make a forward projection on Quality of Service to determine, based on available information, if the future trend is improving, deteriorating or remaining constant. This can be reasonably accomplished through a historical and future trend determination review of reliability considerations (preceding Items II.B, II.C and II.D) coupled with an analysis of projected customer load growth and projected capital investment noted in the following discussion.

E.1 PROJECTED LOAD GROWTH

UNS Electric is projecting overall (Mohave and Santa Cruz counties) customer base growth at an annual average rate of 6.6% for the year end 2006 through year end 2011 time period. They have experienced an actual 5.2% customer base growth rate for the year end 2003

through year end 2006 time period and this overall growth rate is greater in Mohave County at 7.0% than in Santa Cruz at 3.5% for the same period.

The customer base is higher in Mohave County (73,581 total number of customers all classes year end 2006) than Santa Cruz County (20,126 total number of customers all classes year end 2006). The residential class of customers dominates in number in both Mohave and Santa Cruz counties however the growth rate of residential customers is greater in Mohave County (7.6 % growth rate for 2004 through 2011) than in Santa Cruz County (5.0 % growth rate for 2004 through 2011).

The MWH sales figures generally follow the customer trends cited above.

The Mohave projected customer and load growth rates are within Staff's expectations in consideration of anticipated residential and commercial construction primarily in the Kingman and Havasu areas. This high growth is due to an influx of retirees from California, an influx of Nevada residents facilitated by the soon to be completed Hoover Dam Bypass as well as the historical load growth of the area.

The Santa Cruz projected customer and load growth rates are also within Staff's expectations in consideration of historical trends and the general lower growth rates projected as compared to Mohave.

In summary for growth, UNS Electric has experienced high customer and load growth and will likely continue to experience high growth rates. The growth is more pronounced in Mohave County.

E.2 PROJECTED CAPITAL INVESTMENT

UNS Electric will require future electric system capital investment in all major capital cost classes (new business, distribution system reinforcement, transmission and production) to provide service to new customers and ensure that overall reliability is adequate. The new business class includes all distribution lines and meters to supply new customers. The distribution system reinforcement class includes all new and upgraded distribution lines and substations. The transmission system class includes all new and upgraded transmission lines and substations (rated 69 kV and higher). The production class includes upgrades to power plant facilities.

UNS Electric has provided project specific information and cost for their capital budget plans for the years 2007 through 2011 as requested and itemized by the subject cost classes and further by Mohave and Santa Cruz counties. The requested information provided to Staff was submitted under a "Protective Agreement" requiring continued confidentially of the information. Staff therefore addresses UNS Electric's capital program in general terms.

Staff has analyzed the projected expenditures and projects for the years 2007 through 2011 in each service territory, Mohave County and Santa Cruz County and further itemized by cost classes previously noted. Staff believes the projected capital expenditures are appropriate in consideration of the projected growth rates noted in Item II.E.1, the reliability issues noted in Items II.B and II.C and the transmission issues noted in Item II.D. This does not however, imply a specific treatment or recommendation for rate base or rate making purposes in any UNS Electric's rate filings.

F. CONCLUSIONS FOR QUALITY OF SERVICE

Based on the review of UNS Electric's customer reliability measures, transmission system review, anticipated growth and future Construction Work Plans, it is Staff's conclusion that:

1. UNS Electric is supplying its customers in both the Mohave and Santa Cruz service territories with reliable electric service. The Distribution Reliability indices are heavily influenced by major storms and the rural nature of parts of the service territories.

2. The UNS Electric transmission system is adequately supplying both service territories; however there are several identified issues in the 2006 BTA that require resolution and UNS Electric is addressing these issues.

3. The load and customer growth rates of UNS Electric are reasonably projected based on past load and customer growth rates and overall population growth expected for Arizona. Both service territories are experiencing high growth rates with Mohave County experiencing a higher rate than Santa Cruz.

4. UNS Electric projects investment in its capital plant over the next five years in a manner that indicates new customers will be adequately and timely served and all customers can expect a reasonable level of reliability. UNS Electric's Five Year Construction Work Plan is appropriate in consideration of the expected growth and system reinforcement needs. This conclusion, however, does not imply a specific treatment or recommendation for rate base or rate making purposes in any UNS Electric's rate filings.

5. UNS Electric has an effective outage measurement system in Santa Cruz County with the ability to produce a variety of metrics. Staff believes UNS Electric would increase the value of this system to its customers and further improve reliability by additionally employing a metric to identify the worst performing feeders on a minutes (or hours) per customer affected per year measure in Santa Cruz County. The metric would then be used to take appropriate action on the worst performing feeders each year.

6. UNS Electric is moving toward an effective outage measurement system in Mohave County which should be similarly capable of producing a variety of metrics. Staff believes UNS Electric in Mohave County should adopt similar approaches to outage

measurement and corrective action as Santa Cruz County when the Mohave County tools to do so become available.

III. USED AND USEFUL ASSESSMENT

A. FRAMEWORK

A used and useful determination requires a physical survey of new and improved facilities to assure completion of construction, validation that equipment is fully operational, and that the facilities meet National Electric Safety Code ("NESC") requirements per Arizona Administrative Code R14-2-208. The investigator's level of industry experience is also critical in assembling criteria by which a valid sample of facilities is selected for field observation.

During electric facility site visits Staff generally ascertains: 1) facility security, 2) that proper safety and fire protection measures are employed, 3) all equipment have been constructed in compliance with NESC requirements, and 4) the operational status of facility. The site must be secure with proper height enclosures topped with either barbed wire or razor ribbon, and gate(s) and control house(s) are locked. Proper signage must be prominently displayed to inform the public that the facility poses an electric safety hazard. Each site is observed to ascertain that it is a safe working environment. Employee adherence to safe operating practices is also observed in the field. Particular attention is given to fire extinction capability, proper separation of equipment or use of fire wall barriers, and existence of oil cache basins for transformers.

Confirmation that equipment exists in the field and is operational is a prerequisite for a used and useful determination. Therefore the operational readiness status of all onsite equipment is noted. Presence of a properly maintained substation DC battery supply is verified. Equipment maintenance needs are also observed and maintenance practices confirmed. Storage of damaged or non-useable equipment onsite is discouraged. However, onsite storage of equipment for future construction projects or staging of maintenance and repair activities at remote sites is an acceptable practice. Storage of a mobile or spare transformer at a remote substation is an example of this practice.

B. PROJECT SELECTION

This used and useful determination of UNS Electric's capital improvements for the 36 month period prior to the end of the test year (June 30, 2006) is based upon inspection of a sampling of UNS Electric's facilities and review and analysis of the company's response to data requests concerning its capital improvements. Choosing an appropriate sample of facilities to inspect is a fundamental requirement in performing any valid used and useful determination. Normally, Staff would prefer to limit the project review to projects placed in service during the test year (ending June 30, 2006) however UNS Electric's data request response to this question produced a listing too short to allow a representative selection of projects. Subsequently, UNS Electric provided a listing of projects placed in service in the 36 month period ending June 30,

2006 which allowed for a representative selection of projects in both the Mohave and Santa Cruz counties.

It was determined that a site visit of UNS Electric's facilities and an office visit to review the Information Technology systems and other records was needed for the used and useful determination. However, UNS Electric has a large inventory of existing, new and upgraded facilities located state-wide. This made selection of a sample of facilities for field observation a necessity. Therefore, Staff organized its field visits by UNS Electric's major service territories in Mohave and Santa Cruz counties and selected a reflective sample of generation, transmission and distribution facilities in each jurisdiction.

Staff reviewed the listing of projects provided by UNS Electric and selected representative projects for further review. Five projects were selected for Santa Cruz County and five for Mohave County with a mix of Distribution, Transmission, Production and General Plant categories. The projects for both Santa Cruz County and Mohave County are listed in the attached Exhibit 1. Consideration for review was given to some projects that appeared to have a customer contribution element to see also how customer reimbursement was addressed in the rate base. Staff was also interested in the process used by UNS Electric to determine the need and costs for projects and the associated approval process. Also, confirmation through an independent and directly linked document was reviewed for each project to determine the plant was used and useful by the end of the test year (June 30, 2006) with those projects placed in service near the end of the test year receiving a higher degree of scrutiny. Finally, a field review of each project was conducted (or office demonstration in the case of the Information Technology project) to confirm the project was constructed and fairly represented in the information presented.

C. SITE VISITS AND FIELD OBSERVATIONS

Staff prepared a checklist of issues to review and resolve with each project and these checklists are provided herein as Exhibit 2 for Santa Cruz County and Exhibit 3 for Mohave County. A brief summary of the results from each project review is provided below:

Santa Cruz County

1. The Outage Management System ("OMS") Integration Project (rate base inclusion of $142,944.30) was satisfactorily demonstrated to Staff on May 30, 2007 at the Tucson Control Center verifying its usefulness as a tool to track outages and determine likely sources of trouble to expedite field dispatching and service restoration. This is a commonly used technology by utilities with widespread implementation in the utility industry beginning about ten years ago. UNS Electric's OMS application is similar to the OMS applications generally found with other similarly sized utilities. The project was verified as used and useful no later than January 27, 2005. The application is presently used exclusively used in Santa Cruz County.

2. The Valencia 20 Megawatt Turbine (rate base inclusion of $12,169,026.94), located at the Valencia Substation in Nogales, was the subject of a January 22, 2007 field inspection with Staff and UNS Electric representatives and a subsequent inspection on May 30, 2007. Staff reviewed the functionality of the turbine primarily in the January inspection and reviewed other aspects of the used and useful review (and construction work in progress discussed later) at the May review. Staff determined that the used and useful date for the project was June 21, 2006 based on Energy Management System operating logs indicating that the unit was operable from UNS Electric's control center and available to supply load when required. Additional attestations of the turbines readiness on June 30, 2006 were also observed. (Note that June 30, 2006 was the end of the test year and the closeness of these dates to the end of the test year required a close review of the documentation verifying the used and useful date.) The function of the turbine is to supply load when certain system conditions occur (primarily associated with unscheduled outages) and this readiness to supply load is the appropriate used and useful test for this asset. Further review of documentation confirmed that a thorough review of the Valencia turbine alternatives was considered and the Valencia turbine project was authorized and constructed in an appropriate manner. Staff reviewed the security measures associated with this facility, which is part of a larger substation and operations center, and found all standard precautionary measures were in place and fully functional.

3. The 46 kV Canoa to Kantor line (rate base inclusion of $2,282,720.61) was the subject of a January 22, 2007 field inspection with Staff and UNS Electric representatives and a subsequent inspection on May 30, 2007. Staff reviewed the functionality of the line primarily in the January inspection and reviewed other aspects of the used and useful review at the May review. Staff determined that the used and useful date for the project was August 30, 2004 based on Energy Management System operating logs. This line functions as a backup supply when certain system conditions occur (primarily associated with unscheduled outages) and numerous incidents of use were noted in 2005 and 2006 with an average of approximately ten uses each year to supply the Kantor substation under certain outage scenarios. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner.

4. The Kantor 7203 Overhead to Underground Nogales project (rate base inclusion of $333,333.86) was initially field reviewed by Staff and UNS Electric representatives on May 30, 2007. The project involved the replacement of approximately 2.5 miles of overhead 13 kV distribution line with underground cable starting about 0.5 mile from the Kantor Substation and proceeding toward the Whipple Observatory on Mount Hopkins. An original underground installation in the early 1970's served this load; however, an electrical fault incident in early 2000 caused the failure of this portion of the underground feeder and a temporary overhead line was installed to maintain service. State land

permit restrictions required the line to be underground and this was accomplished in 2005/2006 with the construction of the subject project. The in service date for this latest underground installation was determined to be in early 2006 although the requested more positive verification of the in service date was not available and has not been produced at the time of this report. Staff expects this documentation, when provided, will verify the project was in service prior to the end of the test year. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner.

5. The Tubac Golf Resort Overhead to Underground conversion (rate base inclusion of $236,873.96) was initially field reviewed by Staff and UNS Electric representatives on May 30, 2007. The project involved the removal of approximately one mile of 13 kV overhead distribution wire and poles and the installation of a similar length of 13 kV underground distribution cable with four above ground enclosures for fusing and disconnecting laterally tapped lines. The purpose of the project was to allow unencumbered use of a new golf course in the area of the overhead lines. The in service date for this underground installation was determined to be prior to the end of the test year although a precise date was not provided by UNS Electric at the time of this report. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. The customer contribution was undetermined at the time of this report and UNS Electric advised Staff on June 1, 2007 that they would provide documentation after researching the matter further.

Mohave County

1. T3 and London Bridge Substation (rate base inclusion of $2,330,038.55) was initially field reviewed by Staff and UNS Electric representatives on June 6, 2007. The project involved the enlargement of the existing substation and installation of a 24 MVA 69/13 kV transformer, breaker, control house and associated substation equipment in the Lake Havasu area to correct overload conditions on the initial two transformers in the substation. The in service date for this latest installation was verified to be June 29, 2005. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. Staff noted during the site visit that razor wire or barbed wire was not in place protecting the tops of the two gate entrances (as it was around all the masonry wall of the substation) and that oil containment was not present on the two earlier installed substation transformers. UNS Electric advised that they will address the gate protection issue soon and the two existing transformers will have oil containment installed when they are changed out in the next few years. Staff is satisfied with the gate response and conditionally satisfied with the oil containment response. UNS Electric should assure they are in compliance with the Environmental Protection Agency ("EPA") regulations with regard to the Spill Prevention and Countermeasure Control ("SPCC") provisions especially with a

wash immediately adjacent the substation with downhill flow to Lake Havasu approximate one mile away.

2. Install 69/20.8 kV transformer North Havasu project (rate base inclusion of $440,204.04) was initially field reviewed by Staff and UNS Electric representatives on June 6, 2007. The project involved the installation of a 5 MVA 69/13.2 kV transformer and associated facilities in an existing substation to address load growth in the area. The in service date for this latest installation was verified to be March 9, 2005. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff found the facility in good condition and adequate security was in place.

3. Tenant Improvements for New Maricopa (rate base inclusion of $498,260.68) was initially field reviewed by Staff and UNS Electric representatives on June 6, 2007. The project involved the upgrades performed on an office building to accommodate UNS Electric business and engineering office functions. The building was (and still is) leased; however the lease cost is not part of this project. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff found the facility in good condition and adequate security was in place.

4. 69 kV feeders from Havasu North (rate base inclusion of $892,991.37) was initially field reviewed by Staff and UNS Electric representatives on June 6, 2007. The project involved the installation of approximately one mile of double circuit 69 kV line out of Havasu North Substation. The in service date for the installation was verified to be June 27, 2006. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff found the facility in good condition. Staff initially noted the cost of the facility seemed high, close to $900,000 for one mile of 69 kV line, however the observed construction (steel poles, double circuit, drilled piers) was warranted and could reasonably raise the project cost to the actual cost incurred for this project. Staff is satisfied that the work was reasonable and prudent even with the initial planning estimate calling for the project to cost $283,000. Staff however, would generally like to see documentation (which was not available in this case) that justifies project overruns of this magnitude and new budget approval documentation before the work is started. This would, in Staff's opinion, assure that overruns did not displace or delay other more needed projects and that limited capital funds were being wisely spent.

5. Havasu North to Black Mesa Substation (rate base inclusion of $512,605.33) was initially field reviewed by Staff and UNS Electric representatives on June 6, 2007. The project involved the installation of approximately 16 miles of fiber optic

cable on existing poles between Havasu North Substation and Black Mesa Substation and associated communication control facilities at the substations. The project was part of an Agreement with Western Area Power Administration ("WAPA") related to substation control communication. The in service date for the installation was confirmed to be during November, 2005 (exact date not readily available). A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff reviewed the Havasu North termination point only and found the facility in good condition. Staff did note that the control house at Havasu North containing the communication equipment appeared to be more elaborate and more expensive in construction (masonry walls, pitch roof, removable floor in lieu of overhead cable trays) than normally expected in outdoor substations. UNS Electric advised that they were contractually bound by their contract with WAPA to build the facility to WAPA standards. Staff prefers, for economy and function, the control house construction standards noted at other UNS Electric facilities observed on the June 6, 2007 site visits, however, under the contractual circumstances with WAPA, Staff believes the likely extra cost of the project (due to control house construction to WAPA standards) is reasonable.

D. CONSCLUSIONS FOR USED AND USEFUL ASSESSMENT

All projects were determined to be used and useful no later than the dates reported by UNS Electric (subject to confirmation of the Kantor 7203 Overhead to Underground Nogales project).

The Tubac Golf Resort Overhead to Underground Conversion (Task CE64023) with a cost of $236,873.96 and inspected on May 31, 2007 had the appearance of a project that should be reimbursed at least in significant part by the customer since it involved the removal of an overhead 13 kV line and installation of an underground 13 kV line to allow for a developer's golf course. UNS Electric advised that the project appeared to be reimbursable to some extent; however they were not able to provide documentation at the review or by the morning of June 11, 2007 as requested in a follow up notification. Staff suggests this project be considered for removal in projects in rate base unless UNS Electric provides sufficient documentation to prove inclusion is appropriate.

All projects were subject to a UNS Electric approval process that insured a review by management was completed prior to construction. Staff preferred to view a project specific budget approval document for each project with justification, projected cost (company and customer itemized), changes to projected cost when anticipated, and approvals. This is a common industry practice; however, UNS Electric advised this is not their project budgeting process. Staff has no objection to any budgeting process that allows for a timely and thorough review of project cost and benefits by management and believes this was accomplished for the projects in this Used and Useful review. Staff suggests however that significant project overruns, as was apparently the case for the 69 kV feeders from Havasu North project, be more

clearly identified and reviewed prior to construction to assure project overruns are evaluated and agreed to by management.

All substation sites visited were secure with enclosures of the proper height and were topped with either barbed wire or razor ribbon (except London Bridge Substation which is being addressed). All substation and line sites visited displayed construction in compliance with the National Electric Safety Code and were indicative of good utility practices.

One substation, London Bridge, should be reviewed to assure compliance with EPA SPCC regulations.

IV. CONSTRUCITON WORK IN PROGRESS ASSESSMENT

A. FRAMEWORK

A construction work in progress ("CWIP") determination requires a physical survey of new and improved facilities that are included in rate base to assure reasonable progress of construction and validation that equipment will be fully operational by a particular date. The projects included in CWIP by UNS Electric in the Rate Application were not in service at the end of the test year (June 30, 2006) but were anticipated to be in service soon thereafter. Staff therefore believed it was appropriate to review the circumstances of a representative group of CWIP projects and document those findings for further consideration of the CWIP inclusion or exclusion of CWIP in rate base.

During electric facility site visits for CWIP, Staff generally ascertains when the project was placed in service and considered used and useful after the end of the test year (June 30, 2006) or alternatively, if not used and useful, when will this most likely occur and is that reasonably close to the end of the test year. Other considerations covered in the previous Used and Useful Assessment Section III then apply if the project is determined used and useful.

Confirmation that equipment exists in the field or is on order is a determination for a CWIP determination. Therefore the operational readiness status of all onsite equipment is noted.

B. PROJECT SELECTION

Staff reviewed the listing of projects provided by UNS Electric and identified as "Net CWIP June, 2006" totaling $10.8 million after adjustments and which have been included in the rate base application. Staff selected five representative high cost projects totaling $4.2 million for further review. Two projects were selected for Santa Cruz County and three for Mohave County with a mix of Distribution, Transmission, Production and General Plant categories. The projects for both Santa Cruz County and Mohave County are listed in the attached Exhibit 4. Staff was especially interested in the process used by UNS Electric to determine the need and costs for projects and the associated approval process. Also, confirmation through an independent and directly linked document was reviewed for each project meeting the used and

useful criteria after the test year to determine the plant was used and useful by a particular date. Finally, a field review of each project was conducted (or office demonstration in the case of the Information Technology project) to confirm the project was constructed or in the process of construction and fairly represented in the information presented.

C. SITE VISITS AND FIELD OBSERVATIONS

Staff prepared a checklist of issues to review and resolve with each project and these checklists are provided herein as a continuation of Exhibit 2 for Santa Cruz County and Exhibit 3 for Mohave County. A brief summary of the results from each project review is provided below:

Santa Cruz County

1. The Geographic Information System ("GIS") Integration Project (CWIP inclusion of $597,107.00) was satisfactorily demonstrated to Staff on May 30, 2007 at the Tucson Control Center verifying its usefulness as a tool to map and locate distribution facilities in Santa Cruz County. This tool is an integral part of the OMS described earlier to track outages and determine likely sources of trouble to expedite field dispatching and service restoration. The GIS was initially implemented under an earlier project in 2004 and this latest associated CWIP project was undertaken to refine various data points through a field review. This project was completed in April 2007 as verified through the project status report. GIS is a commonly used technology by utilities with widespread implementation in the utility industry beginning about ten years ago. UNS Electric's GIS application is similar to the GIS applications generally found with other similarly sized utilities. The application is presently used exclusively used in Santa Cruz County. Staff therefore considers the work performed through the completion of the project in April 2007 to be appropriate, however this is not a recommendation for or against including the associated CWIP cost in the rate base application.

2. The Valencia Turbine (CWIP inclusion of $1,290,669.04), located at the Valencia Substation in Nogales, is described earlier in Section III for Used and Useful projects. Additionally, this turbine project has a continuing work requirement (CWIP) associated with upgrades to the Valencia Substation to achieve the full functionality of the turbine and associated substation. Staff inspected the site on May 30, 2007 with UNS Electric representatives to review the CWIP portion of this project. UNS Electric has completed extensive bus upgrades in the Valencia Substation and plans one transformer upgrade in the Fall of 2007 and further breaker upgrades through the Spring of 2008. Staff recognizes that substation upgrades performed after close of the test year (June 30, 2006) and as planned at Valencia Substation after this date are common when a generating source is added in close proximity to a substation and is necessary to achieve the full capability of the facility. Staff therefore considers the work performed to date and through the completion of the project in the Spring of 2008 to be appropriate, however this is

not a recommendation for or against including the associated CWIP cost in the rate base application.

Mohave County

1. West Golden Valley Substation (CWIP inclusion of $1,220,855.18) was initially field reviewed by Staff and UNS Electric representatives on June 7, 2007. The project involved the construction of a complete and new 69 kV supplied substation with one 20 MVA 69/21 kV transformer, two outgoing 21 kV feeders and associated facilities to address load growth in the area. The in service date for this latest installation was verified to be November 29, 2006. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff found the facility in good condition and adequate security was in place. Staff therefore considers the work performed through the completion of the project on June 7, 2007 to be appropriate, however this is not a recommendation for or against including the associated CWIP cost in the rate base application.

2. Rhodes Homes (CWIP inclusion of $442,254.92) was initially field reviewed by Staff and UNS Electric representatives on June 7, 2007. The project involved the installation of approximately five miles of 21 kV overhead line to supply service to water pumps for a proposed housing development. The in service date for this latest installation was verified to be May 26, 2006 which was prior to the end of the test year and therefore eligible for Used and Useful plant treatment. This project is fully funded initially by the customer (Rhodes Homes) with UNS Electric refunding the cost under an agreement based on actual revenues received from this new service (refer to March 2, 2006 Letter of Agreement). A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff found the facility in good condition. Staff therefore considers the work performed through the completion of the project on May 26, 2006 to be appropriate and should be considered for Used and Useful treatment with allowance for the customer advance described.

3. Griffith 230 kV Sub 230 kV line (CWIP inclusion of $613,584.64) was initially field reviewed by Staff and UNS Electric representatives on June 7, 2007. The project involved the construction of a new 230 kV/69 kV double circuit line 35 miles in length between the Griffith Generating plant and North Havasu substation. Staff observed with the UNS Electric representative the North Havasu to Franconia 69 kV portion of this project reportedly complete in July, 2006. The majority of the project, the 230 kV line to Griffith Generating plant has been deferred until 2012 or later. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff found the facility in good condition. Staff therefore considers the

work performed through the completion of a portion of the project in July, 2006 to be appropriate, however this is not a recommendation for or against including the associated CWIP cost in the rate base application.

D. CONSCLUSIONS FOR CWIP ASSESSMENT

All projects were determined to be appropriately included in CWIP as of June 2006 although one project, Rhodes Homes which was put in service just prior to the CWIP accounting, could reasonably qualify for Used and Useful treatment. Three of the projects have been completed since the June 2006 CWIP determination (GIS, West Golden Valley and Rhodes Homes) and two projects are continuing (Valencia and Griffith).

All projects were subject to a UNS Electric approval process that insured a review by management was completed prior to the start of construction.

All substation sites visited were secure with enclosures of the proper height and were topped with either barbed wire or razor ribbon.

One project, Rhodes Homes 21 kV supply, was in service on May 26, 2006 which was prior to the end of the test year and therefore eligible for Used and Useful consideration. The project also had a 100% customer advance repayable by UNS Electric when certain load conditions developed.

Staff considers the work performed on all projects in this CWIP review to be appropriate; however, this is not a recommendation for or against including the associated CWIP cost in the rate base application.

V. BLACK MOUNTAIN GENERATING STATION REVIEW

A. FRAMEWORK

UNS Electric has proposed the addition of the future Black Mountain Generating Station ("BMGS") in the rate base application. Pre-filed testimony indicates this new generating station will be a 90 megawatt ("MW") facility located in Mohave County with an expected in service date of 2008 and an estimated cost of $60 million to $65 million. Staff believed it was appropriate and expeditious to conduct a high level review of this facility in conjunction with other office and site reviews described in this report to provide additional information on this project. A check list provided as a continuation of Exhibit 3 was utilized to conduct the review.

B. OFFICE and SITE VISIT OBSERVATIONS

Staff reviewed office records with UNS Electric on June 1, 2007 describing Board of Director's recommendations for the construction of BMGS at a cost of $60 million inclusive of two new 45 MW gas fired simple cycle generators (Consolidated Edison surplus), transmission line interconnection facilities and gas line supply construction. Staff was further advised that

approximately $41 million has been spent to date for purchase of the two turbines, transformers, engineering, materials and generator modification cost. The two turbines are reportedly in Texas undergoing the necessary modifications for use in this application. The remaining equipment is reportedly still with the manufacturers in various stages of completion. The only confirmed fact regarding equipment for this project was that none of the equipment was on site at the time of the June 6, 2007 field review.

Staff did review the site with UNS Electric on June 6, 2007. The site is in open desert south of Kingman off Interstate 10 and less than five miles south of the existing Griffith Generating Plant. The site was reportedly owned previously by Citizens Electric and transferred to UNS Electric. It has a 69 kV line existing on the road frontage of the property which will be used (at least in part) for connection of the plant to the transmission grid. A gas line installation for the plant was in progress on the road frontage and through a portion of the property during the June 6, 2007 site visit. No electrical equipment (or equipment of any kind) was installed or stored on the site at the time of the site visit other than the 69 kV line and gas line previously mentioned.

C. CONSCLUSIONS FOR BMGS

Staff offers only the above observations regarding BMGS as part of the general review of other issues in the area. Staff makes no recommendation for or against inclusion of BMGS in the rate base application.

Used and Useful Review Projects for Arizona Corporation Commission (Docket E-04204A-06-0783)--May 7, 2007

Territory	Project	Proj Description	Task	Task Description	Raw Cost	Date In Service	ACC Comments
MOHAVE Distribution	360062S	T3 Lond Brdg Sub & Wall Expan	HH11317	T3 Lond Brdg Sub & Wall Expan	2,330,038.55	27-Sep-2003	field insp
MOHAVE Distribution	352062S	Install 69/20.8kv Xfmr N Havasu Si	HH11315	Install 69/20.8kV, 5MVA T2 Transformer	440,204.04	29-Jan-2006	field insp
MOHAVE General Plant	310062A	Office Furn & Equip-New (LH)	HH10778	Tenant Improvements for New Maricopa Facility, 2749 Maricopa ,	498,260.68	31-Oct-2004	field insp
MOHAVE Transmission	325061I	69kV Fdrs from Havasu N (King)	7006537	69KV FEEDERS FROM HAVASU NORTH	892,991.37	27-Jun-2006	field insp
MOHAVE Transmission	350062S	North Havasu to BMS Redundant	CE62052	North Havasu Sub to Black Mesa Sub	512,605.33	13-May-2005	field insp
SANTA CRUZ Distribution	366064S	Kantor 7203 OH to UG Nog	141524	Amado- Montosa Road Amado, AZ 85645	333,333.86	12-Feb-2006	field insp
SANTA CRUZ Distribution	302064A	Line Extensions > $10,000(Nog)	CE64023	2003-Tubac Golf Resort - O/H to U/G	236,873.96	16-Oct-2005	field insp
SANTA CRUZ General Plant	322064A	Systems Integr Projects (Nog)	CD1252C	Integrate OMS with UNSE SC	142,944.30	27-Jan-2005	offcie review
SANTA CRUZ Production	383064A	UNSE Valencia Turbine 4	HS10536	Valencia Addition Turbine 4	12,169,026.94	30-Jun-2006	office review
SANTA CRUZ Transmission	363064A	Canoa/Kantor Line	HS10188	46kV Line Construction Canoa to Kantor	2,282,720.61	13-Mar-2005	office review
Grand Total					19,838,999.64		

EXHIBIT 1

Revision #1

Checklist for ACC Santa Cruz Project Review May 30 and 31, 2007
UNS Electric (Docket E-04204A-06-0783)

Used and Useful

1. OMS Integration Project (Task CD1252C)
    a. Demonstration
    b. Review office records
        i. verify in service date
        ii. project scope and approval
    c. Determine Mohave and Santa Cruz applications
    d. Determine link to Reliability Measures (SAIDI, SAIFI, etc)

2. Valencia turbine (Task HS10536)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. What were Valencia turbine alternatives?
    c. How was decision made to proceed with this alternative?

3. 46kV Canoa to Kantor line(Task HS10188)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. How often is this line utilized (hours/ year, events/year, etc.)?
    c. What alternatives were considered in lieu of this line?

4. Kantor 7203 OH to UG Nogales project (Task 141524)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Field review of project

5. Tubac Golf Resort OH to UG project (Task CE64023)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Customer contribution?
    d. Field review of project

CWIP

6. GIS Integration Project (Task CD1250C)
    a. Demonstration
    b. Review office records
        i. verify in service date
        ii. project scope and approval
    c. Determine Mohave and Santa Cruz applications
    d. Determine link to OMS
    e. Determine link to Reliability Measures (SAIDI, SAIFI, etc)

7. Valencia Turbine (Task HS10536)
    a. Cost incurred after in service date comprises what?
    b. When will capital portion of project be complete?
    c. What was initial approved cost of this turbine project?
    d. What is the final expected cost of this turbine project?
    e. Explain if final cost expected to be greater than 10% of initial approved cost.
    f. What is final expected $/MW for this turbine?
    g. How does $/MW compare to industry averages for similar construction?
    h. Field review of project CWIP if necessary

MISCELLANEOUS

8. Worst performing distribution feeders (2005-2006) — field review
    a. Canez C-8203 serving N Pendleton Dr

EXHIBIT 3

Revision #1

Checklist for ACC Mohave Project Review June 5 and 6, 2007
UNS Electric (Docket E-04204A-06-0783)

Used and Useful

1. T3 Lond Brdg Sub & Wall Expan project (Task HH11317)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Field review of project

2. Install 69/20.8kv xfmr N Havasu project (Task HH11315)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Field review of project

3. Tenant Improvements for New Maricopa (Task HH10778)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Field review of project

4. 69 kV feeders from Havasu North (Task 7006537)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Field review of project

5. North Havasu to BMS (Task CE64023)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Field review of project

CWIP

6. West Golden Valley Sub (Task HK10487)
    a. Review office records
        i. Determine expected in service date
        ii. project scope and approval
    b. What is the final expected cost of the project
    c. Verify need for project (how determined)
    d. Field review of project

7. Rhodes Homes (Task 8009729)
    a. Review office records
        i. Determine expected in service date
        ii. project scope and approval
    b. What is the final expected cost of the project
    c. Verify need for project (how determined)
    d. Customer contribution?
    e. Field review of project

MISCELLANEOUS

8. Proposed Black Mountain Generating Station
    a. Review office records
        i. Determine expected in service date
        ii. project scope and approval
    b. What is the basis of the projected $60 million to $65 million cost of the project?
    c. Have funds been expended in CWIP through June 30, 2006? After June 30, 2006?
    d. Verify need for project (how determined)
    e. Field review of project site

9. Worst performing distribution feeders (2004-2006) — field review
    a. No 8008 serving Aqua Fria and Golden Valley
    b. No 8016 serving Aqua Fria and Golden Valley
    c. No 6026 serving Lake Havasu

UNSE, Inc.
ACC STF 2.2
25-Apr-2007

CWIP Review Projects for Arizona Corporation Commission (Docket E-04204A-06-0783)--May 7, 2007

Territory and Category	Project	Project Description	Task Number	Task Description	Cost	Delayed Plant Jun-06	Net CWIP Jun-06	Unitized Jul-06 to Mar-07	Delayed Plant Mar-07	6/30/06 CWIP not in Service as of 3/31/07	Date In Service	Projected In-Service Date
SANTA CRUZ Production	383064A	UNSE Valencia Turbine 4	HS10536	Valencia Addition Turbine 4	13,598,826.00	12,308,156.96	1,290,669.04	13,323,926.23	-	-	30-Jun-2006	
MOHAVE Distribution	330061S	West Golden Valley Subst Kir	HK10847	West Golden Valley Subs	1,220,855.18	-	1,220,855.18	-	2,132,570.33	-	1-Dec-2006	
MOHAVE Distribution	333061A	Line Extensions > $50K King	8009729	RHODES HOMES ARIZONA / GV \	442,254.92	-	442,254.92	-	436,858.34	5,396.58	28-May-2006	
SANTA CRUZ General Plant	322064A	Systems Integr Projects (Nog	CD1250C	Integrate GIS with UNSE SC	597,107.00	-	597,107.00	-	-	597,107.00		Jun-07
MOHAVE Transmission	327062I	Griff to N Hav Sub 230kV (LH	CE62047	Griffith 230kV Sub 230kV Line (LH)	613,584.64	-	613,584.64	-	-	613,584.64		Jul-07
					16,472,627.74	**12,308,156.96**	**4,164,470.78**	**13,323,926.23**	**2,569,428.67**	**1,216,088.22**		

EXHIBIT 4

ALL-STATE LEGAL®
EXHIBIT
S-5
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

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 AND REQUEST FOR APPROVAL OF RELATED. FINANCING	) DOCKET NO. E-04204A-06-0783

DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JUNE 28, 2007

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

My testimony addresses the following issues:

- The Company's proposed revenue requirement.
- Adjustments to test year data
- Rate base, including construction work in progress
- Test year revenues (including number of customers and usage) and expenses.
- Depreciation rates
- The Company's requested modifications to the Purchased Power and Fuel Adjustment Clause ("PPFAC") and Staff's recommendations for features to include in a new PPFAC for UNS Electric
- The Company's proposed ratemaking treatment for a new peaking unit, the Black Mountain Generating Station ("BMGS")

My findings and recommendations for each of these areas are as follows:

- The Company's proposed revenue requirement of a base rate increase of $8.5 million is overstated. I recommend that UNS Electric be authorized a base rate increase of $3.802 million on adjusted fair value rate base.

- The following adjustments to UNS Electric's proposed original cost and fair value rate base should be made:

Summary of Staff Adjustments to Rate Base		**Original Cost**	**Fair Value**
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)
B-1	Remove Construction Work in Progress	$ (10,761,154)	$ (10,761,154)
B-2	Adjust CWIP for Plant in Service by End of Test Year	$ 442,255	$ 442,255
B-3	Plant in Service Addition Subject to Reimbursement	$ (236,874)	$ (236,874)
B-4	Cash Working Capital - Lead/Lag Study	$ 197,541	$ 197,541
B-5	Accumulated Deferred Income Taxes	$ (161,555)	$ (161,555)
	Total of Staff Adjustments	**$ (10,519,787)**	**$ (10,519,787)**
	UNS Proposed Rate Base	$ 140,991,324	$ 177,802,341
	Staff Proposed Rate Base	**$ 130,471,537**	**$ 167,282,554**

- The following adjustments to UNS Electric's proposed revenues, expenses and net operating income should be made (amounts shown are impact on net operating income):

Summary of Staff Adjustments to Net Operating Income

Adj. No.	Description	Increase (Decrease)
C-1	Revenue Adjustment for CARES Discount	$ 32,504
C-2	Remove Depreciation & Property Taxes for CWIP	$ 423,374
C-3	Depreciation & Property Taxes for CWIP Found to be In-Service in the Test Year	$ (16,322)
C-4	Fleet Fuel Expense	$ 43,221
C-5	Postage Expense	$ (10,747)
C-6	Normalize Injuries and Damages Expense	$ 97,668
C-7	Incentive Compensation Expense	$ 27,017
C-8	Supplemental Executive Retirement Plant (SERP) Expense	$ 51,274
C-9	Stock Based Compensation Expense	$ 50,886
C-10	Property Tax Expense	$ 36,686
C-11	Rate Case Expense	$ 68,566
C-12	Edison Electric Institute Dues	$ 5,201
C-13	Other Membership and Industry Association Dues	$ 3,980
C-14	Interest Synchronization	$ (181,343)
C-15	Depreciation Rates Correction	$ 38,748
C-16	Emergency Bill Assistance Expense	$ (12,280)
C-17	Markup Above Cost in Charges from Affiliate, SES	$ -
Total of Staff's Adjustments to Net Operating Income		**$ 658,432**
	Adjusted Net Operating Income per UNS Gas	$ 8,742,011
	Adjusted Net Operating Income per Staff	$ 9,400,443

- The new depreciation rates proposed by UNS Electric presented in Dr. White's direct testimony Attachment REW-2 should be adopted for use in this case, as corrected in the response to data request STF 11.8. The depreciation rates proposed by UNS Electric were generally developed in a manner that is consistent with the Commission's rules for depreciation rates.

- Each of the new depreciation rates proposed by UNS Electric should be clearly broken out between (1) a service life rate and (2) a net salvage rate. By doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

- The new PPFAC proposed by UNS Electric contains objectionable features such as automatically adjusting rates without Commission review and inclusion of costs that would more appropriately be addressed in base rates, as well as raising other concerns, and should therefore be rejected. A new PPFAC for UNS Electric should be developed along the lines of the APS PSA Plan of Administration Staff proposed for the Arizona Public Service Company in Docket Nos., E-01345A-05-0816 et al, after appropriate adjustments to fit UNS Electric's circumstances. The new PPFAC for UNS Electric should become effective June 1, 2008, upon expiration of the Company's all requirements power contract with PWCC.

- The Black Mountain Generation Station ("BMGS") is a 90 MW peaking plant which is being constructed in Mohave County by an affiliate, and which the Company projects will be in service around June 1, 2008 when the PWCC PSA expires. The in-service date for this

plant is too far outside of the test year to qualify for base rate treatment in the current UNS Electric rate case. Staff believes that a more reasonable alternative approach to addressing the ratemaking and cash flow impacts of meeting UNS Electric's power supply will need to be developed. UNS Electric's proposed base rate treatment for BMGS in the current case should be rejected for the reasons described in my testimony, including the uncertainties presently existing with respect to this plant.

I. INTRODUCTION

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

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the Certified Public Accountant ("C.P.A.") examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed C.P.A. and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a member of

the American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 27 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorney generals, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Washington, Washington D.C., and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified before the Commission previously on a number of occasions. Recently, I testified before the Commission in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS" or "Company"), and concerning APS's proposed depreciation rates in Docket Nos. E-01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827, a proceeding involving APS base rates and other matters. I also testified before the Commission in the most recent UNS Gas, Inc. rate case, Docket Nos. G-04204A-06-0463, G-04204A-06-01013 and G-04204A-05-0831.

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the revenue requirement and selected other issues, including new depreciation rates, changes to the Purchased Power and Fuel Adjustment Clause ("PPFAC") proposed by UNS Electric, Inc. ("UNS Electric" or "Company"), and the Company's proposed ratemaking treatment for a new peaking unit, the Black Mountain Generating Station ("BMGS") in the current rate case.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachments RCS-2 through RCS-5 contain the results of my analysis and copies of selected documents that are referenced in my testimony.

II. REVENUE REQUIREMENT

Q. What issues are addressed in your testimony?

A. My testimony addresses the Company's proposed revenue requirement and selected other issues.

Q. What revenue increase has been requested by UNS Electric?

A. UNS Electric is requesting an increase in base rate revenues of $8.507 million, or approximately 5.5 percent. UNS Electric witness James Pignatelli's direct testimony at pages 3-5 attributes the need for the requested increase primarily to increased growth in UNS Electric's service territory and the related increases in capital expenditures and operating costs.

Q. What revenue increase does Staff recommend?

A. Staff recommends a revenue increase of $3.802 million on adjusted fair value rate base. As shown on Schedule A, the comparable base rate revenue increase calculated by Staff on original cost rate base is $3.801 million.

A. Test Year

Q. What test year is being used in this case?

A. UNS Electric's filing is based on the historic test year ended June 30, 2006. Staff's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Several rate base items that tend to fluctuate from month to month, such as materials and supplies and prepayments, are based on a test year average level. Since end of test year net plant in service is used, revenues are annualized based on end of test year customer levels. Additionally, certain expenses, such as depreciation and payroll costs, are annualized based on end of test year levels. This is to ensure that the going-forward revenue and expense levels are matched with the investment (net plant-in-service) used to serve those customers.

As time goes forward, changes in the Company's cost structure will occur. For example, rate base will increase as new plant is added to serve new customers, revenue will increase as customers are added, expenses will fluctuate, etc. It is very important to be consistent with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted.

B. Summary of Company Proposed and Staff Adjusted Revenue Requirement

Q. What did your review of UNS Electric's filing indicate?

A. As shown on Schedule A, based on the rate of return recommended by Staff witness Parcell and the adjustments to UNS Electric's rate base and net operating income recommended by myself and other Staff witnesses, I have calculated a revenue requirement deficiency of $3.802 million for UNS Electric. I recommend a revenue increase of $3.802 million on adjusted fair value rate base. As shown on Schedule A, the

comparable base rate revenue increase calculated by Staff on original cost rate base is $3.797 million.

C. Organization of Staff Accounting Schedules

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 through B-5 and net operating income adjustment Schedules C-1 through C-17.[1]

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the Staff Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony. The schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to earn Staff's recommended rate of return on Staff's proposed Original Cost and Fair Value rate bases. The rate base and operating income amounts are taken from Schedules B and C, respectively. The overall rate of return on original cost rate base of 8.99%, as presented in the prefiled testimony of Staff witness Parcell, is provided on Schedule D for convenience. Schedule D uses the capital structure and cost rates recommended in the prefiled testimony of Mr. Parcell. The operating income deficiency shown on line 5 of Schedule A is obtained by subtracting the operating income available on line 4 (operating income as adjusted) from the required operating income on line 3. Line 7 represents the gross revenue requirement, which is obtained by multiplying the

[1] Schedule C-17 has been reserved for a potential adjustment for charges to UNS Electric from an affiliate Southwest Energy Services, pending receipt of the information requested in data request STF 15.1.

income deficiency by the gross revenue conversion factor (GRCF). The derivation of the GRCF is shown on Schedule A-1.

Q. What is shown on Schedule B?

A. Page 1 of Schedule B presents UNS Electric's proposed adjusted test year Original Cost and Fair Value rate base and Staff's proposed adjusted test year Original Cost and Fair Value rate base. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically UNS Electric Schedule B-1. Staff's recommended adjustments to rate base are summarized on Schedule B.1.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is UNS Electric's adjusted test year net operating income, as provided on Company Schedule C-1. Staff's recommended adjustments to UNS Electric's adjusted test year revenues and expenses are summarized on Schedule C.1. Each of the adjustments are discussed in this testimony. Schedules C-1 through C-16 provide further support and calculations for the net operating income adjustments I am recommending.

Q. What is shown on Schedule D?

A. Schedule D summarizes the capital structure and cost of capital that was proposed by UNS Electric and the capital structure and cost of capital that is recommended by Staff witness Parcell. Schedule D also presents the derivation of Staff's recommended cost of capital for use with the Staff's adjusted fair value rate base.

D. Return on Fair Value Rate Base

Q. How was the fair value basis of rate base determined?

A. As shown on Attachment RCS-2, Schedule B, the fair value rate base was determined by averaging Original Cost and reconstruction cost new depreciated (RCND) rate base information. For purposes of this presentation, I have used the Company's RCND information as the starting point for the fair value rate base. However, using such RCND information for a utility that was recently purchased in an arms' length transaction at a substantial discount to book value could result in substantially overstating the fair value rate base.

Q. Please explain how using the RCND information presented by UNS Electric could result in substantially overstating the fair value rate base.

A. UNS acquired the electric utility from Citizens Communications in August 2003. As of August 11, 2003, the date of the acquisition, the fair value of the assets acquired from Citizens would be equal to the purchase price paid by UniSource.[2] The acquisition of the electric utility was the result of an arm's length transaction between a willing and informed buyer and a willing and informed seller.[3] Reconstructed cost new ("RCN") information, reconstructed cost new depreciated ("RCND") information, Handy-Whitman Index information, Marshall Index information, and Bureau of Labor Statistics index information was given little or no weight by UniSource in deciding how much to pay for the electric utility.[4] The arm's length transaction that has occurred demonstrates that the RCND was not a good estimate of the "fair value" for this utility as of the date of the acquisition. The price paid in the arm's length transaction would represent the "fair value" of the utility as of the date of acquisition. The price paid was substantially below

[2] See response to STF 3.87a
[3] Response to STF 3.87b.
[4] Response to STF 3.87c.

the original cost depreciated book value. Because the acquisition occurred fairly recently (August 11, 2003), this suggests that using RCN and RCND information to establish the fair value of the utility rate base in the current case could result in a substantial overstatement of fair value rate base.

Q. How did UNS Electric determine the rate of return to apply to fair value rate base in its filing?

A. In UNS Electric's own filing, as shown on Schedule A-1, the Company adjusted the return that is to be applied to fair value rate base downward, consistent with long-standing Commission practice, such that the revenue requirement produced by both the original cost rate base and the fair value rate base would not result in an excessive return on equity to the utility. UNS Electric's calculation of return on fair value rate base in the instant case is also consistent with the way the return was applied to the fair value rate base in the original rate case filing of its affiliate, UNS Gas, in Docket No. G-04204A-06-0463.

Q. Has the Commission's traditional calculation of return on fair value rate base been called into question by a recent Court of Appeals decision?

A. Yes. The Commission's traditional calculation of return on fair value rate base calculation has been called into question by a recent Arizona Court of Appeals ruling involving Chaparral City Water Company. In that ruling, the Arizona Court of Appeals found that Staff's determination of operating income ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution.

Q. What guidance for calculating the return on fair value rate base does that Court of Appeals decision provide?

A. First, the Court of Appeals specifically stated that the Commission was not bound to apply an authorized rate of return that was developed for use with an original cost rate base, without adjustment, to the fair value rate base. Page 9 of the Court of Appeals decision stated that: "Chaparral City ... asks that the Commission be directed to apply the 'authorized rate of return' to the fair value rate base rather than to the OCRB, as Chaparral City contends was done here." At page 13, paragraph 17, the Court of Appeals decision states as follows: "The Commission asserts that it was not bound to use the weighted average cost of capital as the rate of return to be applied to the FVRB. The Commission is correct." Thus, the Court of Appeals clearly stated that the Commission is not bound to apply to the FVRB the same weighted average cost of capital that was developed for application to the OCRB.

At pages 13-14, paragraph 17, the Court of Appeals decision stated that: "... the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." At page 13, the decision states: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

Q. Has a remand proceeding been established by the Commission to address the calculation of the return on fair value rate base, i.e., to address the ruling in the Court of Appeals decision?

A. The Commission has opened a docket to address such issues in a Chaparral City remand proceeding.

Q. Did UNS Electric address the Chaparral decision in its Direct Testimony in this case?

A. No. The Company's Direct Testimony was filed on December 15, 2006 and the Court of Appeals' ruling in Chaparral City was issued on February 13, 2007. However, in the recent UNS Gas case, at page 28 of his rebuttal testimony, Mr. Grant, the Company's cost of capital witness, presented a new position concerning the return on fair value rate base calculation that was based on his "non-legal understanding" of the recent Arizona Court of Appeals ruling involving Chaparral City Water Company. In the UNS Gas case, Mr. Grant's recommended that, as a result of that ruling, the weighted cost of capital that was developed for use with an original cost rate base, should be applied without adjustment to the fair value rate base. As described in my surrebuttal testimony in the UNS Gas case, Staff strongly disagreed with that recommendation by Mr. Grant.

Q. How has Staff addressed the ruling in the Court of Appeals decision for purposes of the current UNS Electric rate case?

A. In view of the Court of Appeals decision in the Chaparral City case and the Company's position in the UNS Gas case, Staff has appropriately adjusted the weighted cost of capital to the utility's fair value rate base. David Parcell's direct testimony in the instant rate case describes Staff's revision to the return on fair value rate base calculations in view of the recent Court of Appeals decision concerning Chaparral. Staff will also be addressing the return on fair value calculation in the Chaparral City remand proceeding.

On Schedule D of Exhibit RCS-2, I have derived the adjusted weighted cost of capital for application to the FVRB. On Schedule A of that exhibit I have applied Staff's adjustment to the weighted cost of capital as described by Mr. Parcell in his direct testimony. As shown on Exhibit RCS-2, Schedule A, the application of Staff's adjusted weighted cost of capital to the FVRB results in revenue increase of $3.8 million. In this instance, the application of the adjusted weighted cost of capital to the FVRB produces a slightly higher revenue requirement than does the application of the unadjusted rate of return to OCRB.

III. RATE BASE

Q. Have you prepared a schedule that summarizes staff's proposed adjustments to rate base?

A. Yes. As noted above, the adjusted rate base is shown on Schedule B and the adjustments to UNS Electric's proposed rate base are shown on Schedule B.1. A comparison of the Company's proposed rate base and Staff's recommended rate base on an Original Cost and Fair Value basis are presented below:

Summary of Rate Base	UNS Electric	Staff	Difference
Original Cost Rate Base	$ 140,991,324	$ 130,470,748	$ (10,520,576)
Fair Value Rate Base	$ 177,802,341	$ 167,281,765	$ (10,520,576)

The vast majority of the difference between the Company's proposed and Staff's recommended rate base relates to whether Construction Work in Progress should be included in rate base or not.

B-1 Construction Work in Progress

Q. Please explain the adjustment shown on Schedule B-1.

A. UNS Electric has proposed to include $10.8 million of Construction Work in Progress ("CWIP") in rate base. Staff adjustment B-1 removes that amount of CWIP from rate base.

Q. Please discuss UNS Electric's reasons for requesting the inclusion of CWIP in rate base.

A. As described in the testimony of UNS Electric witness Kentton Grant, the Company believes that inclusion of CWIP in rate base is necessary to preserve the financial integrity of the Company. Mr. Grant indicates that, as reflected in the Company's rate application, rate base treatment of the $10.8 million test year CWIP balance provides UNS Electric with approximately $2.1 million in additional annual revenues. He states that denial of this requested rate treatment would have a material adverse impact on the Company's rate relief and future earnings, and would make it difficult for the Company to attract new capital on reasonable terms. The Company has been experiencing robust growth and expects to need access to outside capital to fund system growth and capital improvements. Mr. Grant also states that inclusion of CWIP in rate base is one of the few available tools to help mitigate the effects of regulatory lag. He suggests further that, by including CWIP in rate base in this proceeding, the time period between this rate case and the next rate filing by UNS Electric will hopefully be extended. He indicates that if the Company's proposed rate base treatment of CWIP is denied, the authorized rate of return should be increased, and the Commission should consider an adjustment for plant placed into service after the test year. He points out that the Commission has, on occasion, allowed the inclusion of post test year plant in rate base.

Q. Is inclusion of CWIP in rate base up to the discretion of the Commission?

A. Yes, it is. Staff's understanding is, in specific instances, the Commission has allowed a utility to include CWIP in rate base, but the Commission's general practice has been to not allow CWIP to be included in rate base.

Q. Does Staff agree with the proposal of UNS Electric to include CWIP in rate base in the current case?

A. No. In general, Staff does not favor inclusion of CWIP in rate base unless the utility demonstrates compelling reasons to justify this exceptional ratemaking treatment. For a number of reasons, including the following, Staff does not support UNS Electric's request for rate base inclusion of CWIP in the current case:

1) Inclusion of CWIP in rate base is an exception to the Commission's normal practice, and UNS Electric has not met its burden of proof showing why it requires such an exceptional ratemaking treatment.
2) The CWIP was not in service at the end of the test year. As of June 30, 2006, the construction projects were not serving customers.
3) The Company has not demonstrated that its June 30, 2006 CWIP balance was for non-revenue producing and non-expense reducing plant. Much of the construction appears to be for plant related to serving customer growth, i.e., to be revenue producing. Test year revenues have been annualized to year-end customer levels. However, revenues have not been extended beyond the test year to correspond with customer growth. Hence, including the investment in rate base, without recognizing the incremental revenue it supports, would be imbalanced.
4) While the Company has stated that inclusion of CWIP in rate base could result in deferring the filing of its next rate case, the Company has made no specific enforceable commitments to a filing moratorium period.

Q. Please elaborate on how including CWIP in rate base is an exceptional ratemaking treatment and why the circumstances in this case do not warrant such treatment.

A. CWIP, as the title designates, is not plant that is completed and providing service to ratepayers during the test year. During the test year, it was not used or useful in providing electric service to the Company's customers. The ratemaking process is predicated on an examination of the operations of a utility to insure that the assets upon which ratepayers are required to provide the utility with a rate of return are prudently incurred and are both used and useful in providing services on a current basis. Facilities in the process of being built are not used or useful. The ratemaking process therefore excludes CWIP from rate base until such projects are completed and providing service to ratepayers in the context of a test year that is being used for determining the utility's revenue requirement. In the current UNS Electric rate case, the test year is the twelve months ending June 30, 2006, and the construction projects the Company seeks to include in rate base were not providing service during that period. As a general ratemaking principle, such CWIP should be excluded from rate base.

Furthermore, some of the facilities that are being constructed and are included in CWIP will be used subsequent to the test year to serve additional customers. It would not be appropriate to include the investment that will serve those new customers without also including the revenues that would be received from those customers. In other words, allowance of CWIP in rate base would result in a mismatch in the ratemaking process. Additionally, some of the plant being added, such as main replacements, could result in a reduction in maintenance expenditures which would not be reflected in the test period. The inclusion of CWIP in rate base, therefore, creates an imbalance in the relationships between rate base serving customers and the revenues being provided to the utility from customers who were taking service during the test year. Consequently, CWIP should not

be allowed in rate base unless there are very compelling circumstances which would warrant an exception to the general rule. In the current case, UNS Electric has not demonstrated convincingly that it requires an exception to the Commission's standard ratemaking treatment of excluding CWIP from rate base. It is not appropriate to include the CWIP in rate base, particularly as the projects may result in additional revenues or cost savings which have not been reflected in the test year.

Q. How does UNS Electric accrue a return on construction projects?

A. UNS Electric accrues a return, representing its financing costs during the construction period in an account called Allowance for Funds Used During Construction ("AFUDC"). This AFUDC return accounts for the utility's financing cost during the construction period. Then, when the plant is placed into service, the AFUDC becomes part of the cost of the plant and is depreciated.

Q. If CWIP were to be included in rate base, as requested by the Company, what is UNS Electric's position concerning whether the accrual of AFUDC should cease?

A. This issue is addressed in Mr. Grant's direct testimony at page 30. Mr. Grant recognizes that "the accounting guidelines published by the FERC require utilities to subtract the amount of any CWIP allowed in rate base from the balance of future CWIP eligible for AFUDC accruals." However, he then attempts to carve out an exception for UNS Electric to this required accounting for AFUDC. He states that, because there is only a small amount of AFUDC on the test year balance of CWIP, it would be unfair to require UNS Electric to cease accruing AFUDC on $10.8 million of CWIP on an ongoing basis. He requests that, if the Commission grants the Company's request to include CWIP in rate base, that language be included in the order that authorizes the Company to continue accruing AFUDC on all eligible construction projects.

Q. Does Staff agree with this proposal by Mr. Grant to continue accruing AFUDC even if CWIP were to be included in rate base?

A. No. Mr. Grant's proposal to continue accruing AFUDC on CWIP should be rejected because it is contrary to the accepted accounting guidelines and would result in a double recovery of the financing cost of CWIP. The financing cost for CWIP can be addressed for ratemaking purposes in one of two ways: (1) through the inclusion of CWIP in rate base for a current cash return, or (2) through the accrual of AFUDC, which is added to the construction cost and is ultimately included in the cost of plant and depreciated. It would be improper to give UNS Electric both a cash return on CWIP through its inclusion in rate base and an AFUDC return. If CWIP were to be allowed in rate base, which the Staff is not recommending in this case, then AFUDC accruals on the amount of CWIP included in rate base must cease.

Q. Does Staff agree with UNS Electric's alternative proposal to include post-test year plant additions in rate base, if the inclusion of CWIP in rate base is denied?

A. No. For similar reasons to those described above, Staff does not agree with UNS Electric's proposed alternative of including post-test year plant in rate base.

Q. How does plant that is placed into service between rate case test years typically get reflected in the regulatory process?

A. If the plant is used to serve new customers, the utility receives revenue from those customers. If the plant helps the utility reduce expenses, such as maintenance, the utility benefits from such cost reductions during the intervening period. Once the plant is recognized in rate base in a test year, and rates are reset, the utility earns a cash return on the plant investment, less accumulated depreciation. The related revenues and expense

impacts, including known and measurable expense reductions enabled by the plant, are then also recognized in the ratemaking process.

Q. Is another witness for Staff addressing certain aspects of UNS Electric's request for inclusion of CWIP in rate base?

A. Yes. Staff's rate of return witness, David Parcell, is addressing the determination of a fair rate of return that would allow UNS Electric to attract new capital on reasonable terms. In making his cost of capital recommendations, Mr. Parcell has been made aware of and has taken into consideration UNS Electric's proposal to include CWIP in rate base and Staff's recommendation that CWIP not be included in rate base in this case.

Q. Does Staff's adjustment to remove CWIP from rate base affect UNS Electric's expenses?

A. Yes. UNS Electric had proposed to treat CWIP at the end of the test year as if it were plant in service. Consistent with that, UNS Electric proposed increases to depreciation and property tax expense. Consistent with Staff's recommendation that CWIP not be included in rate base, Staff adjustment C-2, which is described in a subsequent section of my testimony, removes the related UNS Electric adjustments for depreciation and property tax expense.

B-2 Adjust CWIP for Plant In Service by End of Test Year

Q. Please explain Staff's adjustment to CWIP for Plant In Service by the end of the test year.

A. The results of Staff's preliminary field assessment of used and useful review for UNS Electric indicated that one project included in CWIP, Rhodes Homes (task 8009729), with a cost of $442,255 and inspected by Staff on June 6, 2007, was in service on May 26,

2006, which was prior to the end of the test year. This project involved the installation of five miles of 21 kV overhead line to supply service to water pumps for a proposed housing development. For ratemaking purposes, this project should be treated as plant in service because it was in service by the end of the test year. Accordingly, Staff adjustment B-2, adds the $442,255 to rate base as plant in service.

Q. Were there Customer Advances associated with this plant?

A. Yes. Staff's preliminary field assessment indicates that the project is fully funded initially by the customer, Rhodes Homes. A March 2, 2006 Letter of Agreement indicates that the customer will pay to the Company a total Customer Advance of $360,117.

Q. How have the Customer Advances related to this project been reflected for ratemaking purposes?

A. The Company's response to data request STF 15.4(f) indicates that, as of June 30, 2006, UNS Electric had received Customer Advances totaling $360,117 for this project. The Company's response to data request STF 15.4(g) indicates that no additional Customer Advances for this project were received after June 30, 2006. Thus, it appears that the Customer Advances amount related to this project of $360,117 would have already been reflected as such by the Company in its proposed rate base. Consequently, based on the information provided by the Company to date, no additional pro forma adjustment for the Customer Advances related to this project appears to be necessary.

B-3 Plant in Service Addition Subject to Reimbursement

Q. Did Staff's field assessment reveal any other concerns?

A. Yes. Staff's inspection of the Tubac Golf Resort Overhead to Underground Conversion (task CE64023) with a cost of $236,874 had the appearance of a project that should be

reimbursed, at least in significant part by the customer, since it involved the removal of an overhead 13 kV line and installation. UNS Electric advised Staff that the project appeared to be reimbursable to some extent, but was not able to provide documentation of the customer reimbursement. This project should be removed from rate base unless UNS Electric provides sufficient documentation to prove that inclusion is appropriate. The Company's response to STF 15.4(d) states that: "this customer requested work was paid 100% by the customer as a Contribution in Aid of Construction." It was unclear from that response whether the CIAC had been received and recorded by UNS Electric as of June 30, 2006, the end of the test year. If the CIAC had been recorded by UNS Electric by June 30, 2006, the adjustment shown on Schedule B-3 would not be necessary. If the CIAC was received and recorded by UNS Electric after June 30, 2006, the adjustment shown on Schedule B-3 is necessary to properly reflect the Company's net investment in the project, which would be zero, since the project was paid 100 percent by the customer. Depending on when UNS Electric received and recorded the CIAC related to this project, a related pro forma adjustment to Depreciation Expense may also be needed.

B-4 Cash Working Capital

Q. Have you reviewed the Company's request for a working capital allowance?

A. Yes. The Company's working capital request consists of three separate subcomponents. The subcomponents are: (1) a negative cash working capital balance of $2.635 million based on a lead/lag study; (2) a thirteen-month average materials and supplies balance of $5.651 million; and (3) a thirteen-month average prepayments balance of $351,825. As shown on Company Schedule B-5, UNS Electric's rate base reflects a request for working capital of negative $3.368 million. I will address the Company's cash working capital request, along with the lead/lag study UNS Electric provided as support for that request.

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. Does UNS Electric have a positive or negative cash working capital requirement?

A. UNS Electric has a negative cash working capital requirement. In other words, ratepayers are essentially supplying the funds used for the day-to-day operations of the Company. On average, revenues from ratepayers are received prior to the time when the utility pays the associated expenditures.

Q. Did UNS Electric present a lead/lag study in support of its cash working capital requirement?

A. Yes, UNS Electric performed a lead/lag study to calculate the cash working capital requirement in this case. The Company provided its lead/lag study calculations with the work papers provided in the case.

Q. Has UNS Electric made any revisions to the cash working capital calculation included in its filing?

A. No, none of which I am aware.

Q. Are you recommending any revisions to UNS Electric's cash working capital request?

A. Yes. I have reflected the impact of Staff's adjustments to operating expenses and impacts on revenue based taxes. I have also synchronized the calculation with cash working capital with Staff's recommended revenue increase.

Q. What is the result of your cash working capital calculation?

A. As shown on Schedule B-4, UNS Electric's filed cash working capital request should be increased by approximately $197,000.

B-5 Accumulated Deferred Income Tax

Q. Please explain the adjustment to Accumulated Deferred Income Taxes ("ADIT").

A. This adjustment is shown on Schedule B-5, and decreases rate base by $161,555 for the impact of the following:

1) removal of the ADIT related to the Supplemental Executive Retirement Plan ("SERP")[5]; and
2) removal of the ADIT relating to stock-based compensation.[6]

This adjustment to ADIT is necessary to properly coordinate the impact of Staff's related adjustments to operating expenses with the ADIT amount included in rate base.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized Staff's proposed adjustments to operating income.

A. Schedule C summarizes Staff's recommended net operating income. Schedule C.1, present Staff's recommended adjustments to test year revenues and expenses on an

[5] See Staff Adjustment C-8 that has removed the expense related to SERP.
[6] See Staff adjustment C-9 that removes the expense for stock-based compensation.

Arizona jurisdictional basis. The impact on state and federal income taxes associated with each of the recommended adjustments to operating income are also reflected on Schedule C.1. UNS Electric's proposed adjusted test year net operating income is $8.742 million, whereas Staff's recommended adjusted net operating income is $9.406 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1 Revenue Adjustment for CARES Discount

Q. Please explain Staff Adjustment C-1.

A. This adjustment removes UNS Electric's proposed adjustment to reduce electric retail revenue by $52,937 relating to a change proposed by the Company concerning how the discounts for CARES customers are calculated. As explained in the testimony of Staff witness Julie McNeely-Kirwan, Staff disagrees with that Company proposal and recommends that the existing discount rate structure for CARES be retained. It is anticipated that Staff will present further details concerning the rate design impacts of its CARES discount recommendations when Staff files its rate design testimony on July 12, 2007.

C-2 Remove Depreciation and Property Taxes for CWIP

Q. Please explain Staff Adjustment C-2.

A. This adjustment removes the pro forma amounts calculated by UNS Electric for depreciation and property taxes related to the Company's proposal to include CWIP in rate base. As explained above[7], Staff disagrees with the Company's proposal to include CWIP in rate base. Accordingly, Staff has also removed the pro forma depreciation and property tax expense adjustments proposed by UNS Electric. As shown on Schedule C-2, this

[7] See above discussion in conjunction with Staff Adjustment B-1.

reduces the Company's proposed expenses for depreciation by $449,816 and property taxes by $239,696, for a total reduction of $689,512.

C-3 Depreciation and Property Taxes for CWIP Found to Be In-Service in the Test Year

Q. Please explain Staff adjustment C-3

A. This adjustment relates to rate base adjustment B-2. As described above in conjunction with Staff adjustment B-2, Staff's engineering and used-and-useful review revealed that a project that UNS Electric had included in CWIP was actually in service in May, 2006, and thus qualifies as plant in service. This adjustment increases recorded test year expenses to provide for depreciation and property taxes related to a project that UNS Electric had included in CWIP, Rhodes Homes (task 8009729), with a cost of $442,255 that was inspected by Staff on June 6, 2007, and was found to be in service on May 26, 2006, which was prior to the end of the test year. As shown on Schedule C-3, this Staff adjustment increases depreciation expense by $18,265 and property tax expense by $8,317 to reflect the annualized depreciation and property taxes on this item of plant, the Rhode Homes overhead line extension project, that was in service by the end of the test year.

C-4 Fleet Fuel Expense

Q. Please explain Staff Adjustment C-4.

A. This adjustment reduces the Company's proposed post-test year increase for vehicle fleet fuel expense. Staff's adjustment used the weighted average cost per gallon of fuel expense from the three primary suppliers through May 2007, which reflects an average cost per gallon of $2.69. Staff's adjustment follows a similar format to the UNS Electric proposed adjustment for fleet fuel expense. Staff's adjustment allows for a pro forma fuel expense increase of $3,270 based on a cost of gasoline of $2.69 based on UNS Electric's

actual fuel costs. UNS Electric's proposed adjustment is reduced by $70,391, as shown on Schedule C-4.

C-5 Postage Expense

Q. What has UNS Electric proposed for normalized postage expense?

A. UNS Electric has proposed normalized postage expense of $341,321. This is shown on in UNS Electric's workpaper for the Company's proposed postage expense adjustment.

Q. Does the UNS Electric-proposed amount of normalized postage expense reflect the postage rate increase that became effective on May 14, 2007?

A. No. That increase is now known and should be reflected, similar to a known change in tax rates. This postage rate increase has occurred and should be recognized for ratemaking purposes. To derive the adjustment to annualized postage expense to reflect the May 14, 2007 increase, which increased the cost of a first class letter from 39 cents to 41 cents (for an increase of 5 percent), Staff has increased the Company's proposed postage expense by 5 percent. As shown on Schedule C-5, this increases UNS Electric's proposed amount of postage expense by $17,503.

C-6 Normalize Injuries and Damages Expense

Q. Please explain Staff Adjustment C-6.

A. This adjustment normalizes the amount of Injuries and Damages Expense, based on a three-year average through December 2006. As shown in the following table, the amount proposed by UNS Electric is substantially higher than the corresponding amount in each calendar year during UNS Electric's ownership of the utility:

Staff adjustment C-6 reduces test year expense by $159,063.

UNS Electric Injuries and Damages Expense

Test Year Ending 6/30/06	$ 562,403

Comparable Information:

Year	Annual Expense	Exceeds Annual Expense By $	Exceeds Annual Expense By %
2004	$ 352,589	$ 209,814	59.5%
2005	$ 356,992	$ 205,411	57.5%
2006	$ 500,440	$ 61,963	12.4%
Average	$ 403,340	$ 159,063	39.4%

Source: Response to data request STF 3.101

Q. Why is the test year Injuries and Damages expense so high in comparison with the other years?

A. The test year Injuries and Damages expense (Account 925) is so high in comparison with the other years because a number of the types of expenses which are recorded in this account appear to be abnormally high in the test year, and would thus require separate adjustment, if the balance in this account were not normalized, as described above. As one illustrative example, the Company's response to data request STF 11.16 indicates that worker's compensation expense in the test year was $190,028. This test year amount exceeded the 2006 recorded amount and the average for 2004-2006 by approximately $93,000, as summarized in the following table:

UNS Electric Workers Compensation Expense

Test Year Ending 6/30/06	$ 190,028

Comparable Information:

Year	Annual Expense	Exceeds Annual Expense By $	Exceeds Annual Expense By %
2004	$ 129,454	$ 60,574	46.8%
2005	$ 57,111	$ 132,917	232.7%
2006	$ 93,869	$ 96,159	102.4%
Average	$ 93,478	$ 96,550	103.3%

Source: Response to data request STF 11.16

Additionally, the Company's expense for Directors' and Officers' Liability ("D&O") Insurance is recorded in Account 925 and has been increasing substantially, from $22,032 in 2004, to $88,605 in 2005, to $130,330 in 2006, as listed in the responses to data requests STF 3.102 and STF 11.15. The substantially increased cost of such D&O insurance is a concern because the direct monetary benefits of D&O Insurance flow to shareholders. The monetary benefit from D&O Insurance is not enjoyed by ratepayers. Because shareholders benefit materially from this insurance, it may be appropriate to allocate the cost of D&O Insurance equally between shareholders and ratepayers.

In summary, Staff Adjustment C-6 to normalize the expense in Account 925 as shown on Schedule C-6 is believed to be a reasonable approach. By adjusting the total in this account to a normalized level, the additional adjustments that would otherwise appear to be needed to address specific components of the expenses recorded in the account are rendered unnecessary.

C-7 Incentive Compensation

Q. Please explain Staff Adjustment C-7.

A. This adjustment removes 50% of the expense related to the various incentive compensation programs in effect at UNS Electric. In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50% of the incentive compensation expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals; however, there is no assurance that the award levels

included in the Company's proposed expense for the test year will be repeated in future years.

The adjustments to expense for each of UNS Electric's incentive compensation programs are shown on Schedule C-7. The adjustment reduces O&M expense by $42,448. A related impact on payroll tax expense reduces that by $1,553.

Q. Please discuss the UniSource Energy Corporation's Performance Enhancement Program.

A. UNS Electric participates in the same incentive compensation arrangement, the Performance Enhancement Plan ("PEP"), as its affiliate, UNS Gas. As explained in the Company's supplemental response to data request STF 11.5 in the recent UNS Gas rate case, Docket Nos. G-04204A-06-0463 et al, the utility's non-union employees participate in UniSource Energy Corporation's PEP. UniSource Energy Services ("UES") is a subsidiary of UniSource Energy Corporation and the parent company of UNS Electric. The structure of the PEP determines eligibility for certain bonus levels by measuring UES' performance in three areas: (1) financial performance; (2) operational cost containment; and (3) core business and customer service goals. Levels of achievement in each area are assigned percentage-based "scores." Those scores are combined to calculate the final payout. The amount made available for bonuses pursuant to the PEP formula may range from 50 percent to 150 percent of the targeted payment level. The financial performance and operational cost containment components each make up 30 percent of the bonus structure, while the core business and customer service goals account for the remaining 40 percent.

As explained in the Company's supplemental response to data request STF 11.5(c) in the recent UNS Gas rate case, Docket G-04204A-06-0463:

> "In 2005, PEP had a similar structure as 2004 with two primary goals. However, the primary financial goal was now a combined financial measure for UNS Electric, UNS Gas and TEP. The second primary goal measured UNS Electric financial performance, customer and reliability goals, integration goals, and safety and employee goals. Similar to the prior year, each of the two primary goals was weighted equally and PEP only paid if the primary financial goal was met. As stated in the response to STF 11.5 b, the 2005 primary financial goal was not met."

Q. Even though the primary financial goal under the PEP was not met in 2005, were incentive bonuses paid?

A. Yes, they were. As explained in the utility's supplemental response to STF 11.5(b): in the recent UNS Gas rate case, Docket No. G-04204A-06-0463, which describes the same UniSource Energy PEP in which UNS Electric also participates:

> "... the financial performance goal, which was a trigger under the PEP program for UNS Electric, UNS Electric and Tucson Electric Power Company ("TEP"), was not met. The financial performance goal was not met, in part, because of unplanned outages at the coal generating units which required TEP to purchase power on the open market. In discussions with the Board of Directors, the desire was to recognize employee achievements distinct from financial measures. The Board deemed it appropriate to implement a Special Recognition Award to employees for achievements in 2005. Normally, PEP is paid at 50% to 150% of target; the Special Recognition Aware was paid at approximately 42% of the target for each of the operating companies."

C-8 Supplemental Executive Retirement Program Expense

Q. Please explain Staff Adjustment C-8.

A. This adjustment removes 100% of the expense for the Supplemental Executive Retirement Plan ("SERP"). The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the Company 401(k) contributions such that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

Q. Are you aware of any recent Commission decisions that reached similar conclusions regarding the appropriate ratemaking treatment of incentive compensation and SERP expense?

A. Yes. As an illustrative example, in Decision No. 68487, February 23, 2006, in a Southwest Gas Corporation rate case, the Commission adopted Staff's recommendation for an equal sharing of costs associated with that utility's management incentive plan compensation expense, and adopted a recommendation by RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Order 68487 that:

> "Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to

remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers."

Q. What adjustment related to UNS Electric's SERP expense do you recommend?

A. I recommend the adjustment to remove UNS Electric's expense for the SERP, which is shown on Schedule C-8 and reduces O&M expense by $83,506.

C-9 Stock Based Compensation

Q. Please explain Staff Adjustment C-9.

A. This adjustment decreases test year expense by $82,873 for the removal of stock-based compensation to officers and employees. The expense of providing stock options and other stock-based compensation to officers and employees beyond their normal levels of compensation should be borne by shareholders and not by ratepayers.

C-10 Property Tax Expense

Q. Please explain Staff Adjustment C-10.

A. This adjustment reflects the known statutory assessment ratio of 23.5 percent applicable for 2008, when rates in this case are expected to become effective. The Arizona State Legislature passed House Bill No. 2779 which set a new rate schedule for property tax

assessments. The new assessment rate schedule provides for decreasing the 25 percent rate applicable in 2005 in 0.5 percent steps each year until a 20 percent rate is attained in 2015. The Company's calculation used a 24 percent assessment rate and thus fails to recognize the impact of this known tax change prospectively.

Q. How did Staff determine its recommended assessment rate?

A. The current assessment rate in 2007 is 24 percent, and this will decrease to 23.5 percent for 2008, which is when rates established in this proceeding are to be in effect. Staff concluded that since the Commission approved rates are expected to become effective in early 2008, and the Company's anticipated rate case interval is three years, as evidenced by the Company's proposed normalization period for rate case expense, the property tax assessment ratio that will be in effect for 2008 of 23.5 percent is appropriate.

In terms of determining the recommended assessment ratio, I also considered how Staff's recommendation in the current UNS Electric rate case compares with Staff's similar determination in the recent Southwest Gas and UNS Gas rate cases. This comparison is summarized in the following table:

Utility:	UNS Electric, Inc.	UNS Gas, Inc.	Southwest Gas Corp.
Docket:	E-04204A-06-0783	G-04204A-06-0463	G-01551A-04-0876
Test Year Ended:	June 30, 2006	December 31, 2005	August 31, 2004
New Rates Effective:	Early 2008	mid-2007	Order issued 2/23/06
Estimated Filing Interval:	3 years or less	3 years	3 to 4 years
Assessment Rate Used:	23.5	24 percent	24.5 percent
Corresponding Effective Year:	2008	2007	2006

In the Southwest Gas case, it appears that the utility, Staff and RUCO all ultimately agreed on the appropriateness of using a 24.5 percent assessment rate effective for 2006 in conjunction with the test year in that case ending August 31, 2004. The information shown above for UNS Gas reflects Staff and RUCO proposals, with which UNS Gas did

not agree. I believe the appropriateness of using the known 23.5 percent assessment rate in the current UNS Electric rate case is supported by the comparison in the above table.

Q. What is Staff's recommended property tax expense adjustment?

A. As shown on Schedule C-10, Staff's recommended adjustment reduces UNS Electric's proposed property tax expense by $59,747.

C-11 Rate Case Expense

Q. Please discuss the allowance for rate case expense.

A. UNS Electric's filing requests an amount of $600,000 for rate case expense normalized over a three year period, for an annual allowance of $200,000 per year.

Q. Does the fact that this is the first rate case for UNS Electric justify a $600,000 rate case expense?

A. No. While the current case may be the first rate case for this utility operation <u>under its current ownership</u>, it isn't the first rate case for this utility. This electric utility had periodic, recurring rate cases under its prior ownership by Citizens Utilities. The transfer of ownership should not be an excuse for charging ratepayers for what appear to be excessive amounts of rate case cost.

Moreover, the current UNS Electric rate case is similar to and presents many of the same issues, such as revisions to a PGA/PPFAC mechanism, adjustments to operating expenses for incentive compensation and SERP, etc., that were recently addressed by the Commission in Docket No. G-01551A-04-0876, a rate case involving a large gas distribution utility in the state, Southwest Gas Corporation. Staff believes that the

Southwest Gas case provides a reasonable benchmark for what a reasonable allowance for rate case cost should be in the current UNS Electric rate case.

Q. What does Staff recommend for the allowance for rate case expense for UNS Electric in this proceeding?

A. Staff recommends an annual allowance of $88,333 per year, based on a total of $265,000 normalized over three years. The total amount of rate case expense requested by UNS Electric of $600,000 and the annual allowance of $200,000 per year over a three-year period appears to be excessive and would represent an unreasonable burden on ratepayers. The amount of $600,000 requested by UNS Electric is over 2.5 times as high as the amount of rate case expense allowed by the Commission in the Southwest Gas rate case, which was $235,000 in total, and which was normalized over a three-year period. Although Southwest Gas is a larger utility than UNS Electric, the current UNS Electric rate case has similarities to the Southwest Gas rate case in terms of both the scope of issues in the cases, and the majority of each application being sponsored by in-house or affiliated company staff. Staff Adjustment C-11 reduces the $200,000 annual amount that was requested in the Company's original filing for rate case expense by $111,667 to provide for an annual allowance of $88,333 per year.

C-12 Edison Electric Institute Dues

Q. Please explain Staff's proposed adjustment for Edison Electric Institute dues.

A. This adjustment is shown on Schedule C-12 and reduces test year expense by $8,470. It reflects the removal of 49.93 percent of EEI core dues and 100 percent of the EEI UARG dues.

Q. How does Staff's proposed adjustment for Edison Electric Institute dues compare with UNS Electric's proposed treatment of such dues?

A. As noted above, Staff's adjustment reflects the removal of 49.93 percent of EEI core dues and 100 percent of the EEI UARG dues. UNS Electric's filing reflected the removal of 20 percent of the EEI core dues (apparently only the direct lobbying portion), and none of the EEI UARG dues.

Q. How did you determine the portion of EEI core dues that should not be charged to ratepayers?

A. I obtained a classification by NARUC category for EEI Core Dues activities for the year ended December 31, 2005. This is shown on Schedule C-12, page 2. EEI Core Dues relating to the following activities should be excluded from rates:

- Legislative Advocacy
- Regulatory Advocacy
- Advertising
- Marketing
- Public Relations

The sum of EEI Core Dues activities for these NARUC categories totals 49.93 percent, as shown on Schedule C-12, page 2.

Q. What is the purpose of the NARUC-designated categorization of EEI expenditures?

A. The purpose of the NARUC-designated categorization of EEI expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of

costs directly incurred by the state's utilities for similar activities. Certain expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit. The NARUC-designated categories of EEI expenditures are thus intended to be helpful to state utility regulatory commissions.

Q. Was this same percentage for the EEI core dues disallowance recently used in any other electric utility rate cases?

A. Yes. The Arkansas Public Service Commission in Docket No. 06-101-U, an Entergy Arkansas, Inc., rate case, in Order No. 10 (6/15/07) adopted a similar adjustment to reflect the disallowance of 49.93 percent of EEI core dues. This 49.93 percent disallowance of EEI core dues corresponds to the above-identified activity categories.

Q. What is UARG?

A. UARG is the EEI Utility Air Regulatory Group, which EEI sometimes also refers to as the "Separately Funded Activity" ("SFA") for Environment. This group, like the other EEI separately funded activities (or "U-groups") advocates the electric utility industry's views before legislative, regulatory, and judicial bodies. Therefore, these costs should not be borne by ratepayers. I recommend disallowing $5,477 of UARG dues from the cost of service.

Q. Did UNS Electric provide information from EEI indicating the non-deductible percentage for UARG?

A. Yes. A letter from EEI dated July 26, 2006, states that 100 percent of such activities are non-deductible:

> "We have completed the calculation of EEI's actual expenditures relating to influencing legislation for calendar year 2005. A total of ... 100% of the assessment for the SFA for Environment were devoted to non-deductible activities."

EEI's letter refers to UARG as the SFA for Environment. EEI's invoices refer to the SFA-Environment by its traditional designation, UARG. Association activities such as lobbying and influencing legislation is considered a "non-deductible activity" for federal income tax purposes. Accordingly, 100 percent of the UARG dues related to "non-deductible activity" should be disallowed for ratemaking purposes.

C-13 Other Membership and Industry Association Dues

Q. Please explain Staff's proposed adjustment for Other Membership and Industry Association Dues.

A. This adjustment reduces test year expense by $ $6,482, as shown on Schedule C-13 to remove other discretionary membership and industry association dues which are not needed for the safe and reliable provision of electric utility service.

This adjustment includes the removal of the $1,750 for the Arizona-Mexico Commission identified in the Company's response to data request STF 3.55. The Company's response to Mr. Magruder's second set of data requests, MM DR 2.27, states that: "The $1,750 for the Arizona-Mexico Commission should have been removed from expenses included in the revenue requirement. This invoice was overlooked in error and will be adjusted out of test year expense."

Q. Do you have any other recommendations concerning UNS Electric's participation in industry associations that the Company seeks to charge to ratepayers?

A. Yes. With any future rate filing in which UNS Electric may seek rate recovery of industry association dues or trade associations, the Company should include a cost-benefit analysis, reflecting all benefits it deems it has received over the prior 24 month period from any trade organization for which it seeks membership cost recovery. Such cost-benefit analysis should quantify each utility-asserted benefit of membership, showing the tie between the organization's activities and the benefits which are directly provided to ratepayers.

C-14 Interest Synchronization

Q. Please explain your interest synchronization adjustment.

A. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, my proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Schedule C-14. This adjustment increases income tax expense by the amount shown on Schedule C-14 and decreases the Company' achieved operating income by a similar amount.

C-15 Depreciation Rates Correction

Q. Please explain Staff adjustment C-15.

A. This adjustment reduces annualized depreciation expense by $63,105 to correct the Company's proposed depreciation rate for transportation equipment. The Company's response to data request STF 3.39 states that:

"Foster Associates inadvertently failed to include a 10 percent net salvage rate for UNS Electric transportation equipment. The impact of this oversight would be a further reduction in 2006 annualized accruals of $143,297. It is the opinion of Foster Associates that the magnitude of the additional depreciation reduction does not warrant a refilling of the depreciation study."

The Company's response to data request STF 11.8 provided additional details on the impact of the depreciation rate correction.

Q. Do you agree with the Company's depreciation witness, Dr. Ronald White, that the magnitude of the additional depreciation reduction does not warrant a re-filing of the depreciation study?

A. Yes. I agree that the depreciation rate study sponsored by Dr. White does not need to be re-filed. However, the error correction should be reflected in the calculation of annualized depreciation expense. Additionally, the Commission should approve and UNS Electric should then use prospectively, the corrected depreciation rates that were provided in the response to data request STF 11.8 (as opposed to the uncorrected rates that were presented in Dr. White's exhibit).

Q What is the impact on depreciation expense?

A. As shown on Schedule C-15, page 1, the Company's proposed annualized depreciation expense (Account 403) is reduced by $64,872 and the amortization of utility plant acquisition adjustment (Account 406, which is a credit to expense) is reduced by $1,767, for a net reduction to operating expense of $63,105.

Q. What is shown on the other pages of Schedule C-15?

A. The other pages of Schedule C-15 show the calculation of this adjustment in detail. Schedule C-15, page 2, shows the following information:

- Section A shows the Depreciation Rates for Transportation Equipment (before correction) as applied to the Transportation Equipment plant balances by UNS Electric (from the UNS Electric workpapers). This produced total annualized depreciation on Transportation Equipment of $1,534,515.
- Section B shows the corrected Depreciation Rates for Transportation Equipment as applied to the Transportation Equipment plant balances. This produces total annualized depreciation on Transportation Equipment of $1,378,197.
- Section C shows the derivation of Staff's pro forma adjustment for Depreciation Expense in Account 403. The decrease to annualized Depreciation Expense on Transportation Equipment of $156,318 is multiplied by the O&M percentage of 41.5 percent to derive the decrease in Depreciation Expense charged to O&M of $64,872.

Schedule C-15, page 3 of 4, shows this same result (as a check) with references to detailed supporting information that is shown in Schedules C-15.1 and 15.2, respectively.

Schedule C-15, page 4 of 4, is similar to the presentation on Schedule C-15, page 2. Page 4 shows the derivation of the Staff adjustment for the Amortization of Acquisition Discount, Account 406, of $1,767.

Q. You mentioned that Schedule C-15 references Schedules C-15.1 and C-15.2. What is shown on those Schedules?

A. Schedule C-15.1 reproduces the Company's detailed calculation workpapers relating to the Company's depreciation annualization adjustment. Schedule C-15.2 presents the same information, in the same format, but with the corrected Depreciation Rates for Transportation Equipment. As noted above, the corrected Depreciation Rates for Transportation Equipment were provided by the Company in response to data request STF 11.8.

Q. Do you address other aspects of the new depreciation rates proposed by UNS Electric, not directly related to a Staff operating expense adjustment, in another section of your testimony?

A. Yes. In Section V of my testimony, I address other aspects of the new depreciation rates proposed by UNS Electric.

C-16 Emergency Bill Assistance Expense

Q. Please explain Staff Adjustment C-16.

A. This adjustment increases test year expense to be included in the base rate revenue requirement determination by $20,000 to provide for an increase requested by the Company for emergency bill assistance. UNS Electric had included this $20,000 in its request for increased funding for its low-income weatherization program. UNS Electric also requested that the low-income weatherization program be included in the Commission-approved Demand Side Management (DSM) programs. Staff agrees with increasing the Company's requested allowance for emergency bill assistance by the $20,000, but disagrees that this should be part of a DSM program or that this particular expense should be included in the separate DSM surcharge rate. Accordingly, Staff has

reflected the $20,000 increase in emergency bill assistance as an increase to operating expenses, so this can be included in base rates, and has excluded this expense from DSM programs. As shown on Schedule C-16, this adjustment increases operating expense by $20,000. The testimony of Staff witness Julie McNeely-Kirwan contains further explanations of Staff's reasons for this treatment.

C-17 Markup Above Cost for Charges from Affiliate, Southwest Energy Services

Q. How is UNS Electric charged for services provided by the affiliated company, Southwest Energy Services?

A. As described in the Company's responses to data requests STF 3.70, STF 10.4, STF 10.5, STF 10.6 and STF 11.10, Southwest Energy Services ("SES") is an affiliated company that performs supplemental work force services to UNS Electric and other affiliates. SES provides meter reading services for UNS Electric. SES began ~~reading~~ performing UniSource Energy Service, Inc.'s electric meter reads in February 2005. As described in the response to data request STF 10.6,

> "When SES provides supplemental work force services to UNS Electric, TEP or other affiliates, SES charges a 10% mark-up on the base wages of the supplemental worker.
>
> In addition, SES charges the cost of employer's taxes, workers' compensation and benefits. For example, for a supplemental administrative assistant that is paid $12.00 per hour, SES would charge ($12.00 + $1.20 markup) per hour, plus employer's taxes, worker's compensation and benefits (cost)."

Staff data request STF 15.1 requested additional information in order to quantify an adjustment to remove the 10 percent markup in the charges from the affiliate, SES, from

UNS Electric's test year expenses. As of June 26, 2007, the response to STF 15.1 stated that: "UNS Electric is in the process of gathering information and will provide the response to this data request as soon as the compilation is available."

V. DEPRECIATION RATES

Q. Please discuss the new depreciation rates that UNS Electric has proposed.

A. The development of new depreciation rates is addressed in the testimony of UNS Electric witness Ronald White, who sponsors the Company's 2006 depreciation rate study. The table presented at page 10 of Dr. White's testimony summarizes the overall changes. The depreciation rates proposed by primary account are equivalent to a composite rate of 4.18 percent. This is a reduction of 0.35 percentage points in comparison to the current composite rate of 4.53 percent. On December 31, 2005, plant investment, the difference between the current and proposed new depreciation rates produces a decrease in annualized depreciation expense for the electric utility of $1,231,943. This is shown on Statement B, at numbered page 18 of Dr. White's Attachment REW-2.

As described in the Company's responses to data requests STF 3.39 and STF 11.8, an additional reduction in annualized depreciation expense at the new rates, computed on December 31, 2005 plant investment of $143,297 is necessary to correct an error in the depreciation study. As described in the response to data request STF 3.39, the error resulted from Foster Associates' inadvertent failure to include a 10 percent net salvage rate for UNS Electric transportation equipment. The results of correcting this error are summarized in the following table:

Summary of Proposed Depreciation Rates and Accrual Before and After Error Correction

Line	Description	12/31/2005 Plant Investment (A)	2006 Annualized Accrual Present (B)	Proposed (C)	Difference (D)
	Proposed Before Error Correction [a]:				
1	Total Utility	$ 347,839,970	$ 15,761,231	$ 14,529,288	$ (1,231,943)
2	Equivalent Composite Rate		4.53%	4.18%	
	Proposed After Correcting Error [b]:				
3	Total Utility	$ 347,839,970	$ 15,761,231	$ 14,385,991	$ (1,375,240)
4	Equivalent Composite Rate		4.53%	4.14%	
5	**Difference in total annual accrual due to error correction [b]**			$ (143,297)	$ (143,297)

Source:
[a] UNS Electric, Direct Testimony of Dr. Ronald White, Exhibit REW-2, pages 3 and 18.
[b] Responses to Data Requests STF 3.39 and 11.8

Q. Why is the Staff adjustment C-15, which you discussed above, different in amount from the $143,297 correction to UNS Electric's annual depreciation accrual identified in the responses to data requests STF 3.39 and STF 11.8 and summarized in the above table?

A. It is different because of three factors. First, the $143,297 was calculated using plant investment as of December 31, 2005, whereas Staff adjustment C-15 used the Company's June 30, 2006 adjusted plant balances. Second, the $143,297 reflects the impact on the annual depreciation accrual before considering that a portion of the depreciation on transportation equipment is capitalized and therefore is not charged to O&M expense. Staff adjustment C-15 reflects the expensed portion of depreciation on transportation equipment. Third and finally, Staff adjustment C-15 reflects a related impact of the depreciation rate correction on amortization of the acquisition adjustment discount, which is not reflected in the $143,297.

Q. Please briefly describe the information you reviewed concerning UNS Electric's proposed depreciation rates.

A. The information I reviewed included the Commission's rules regarding depreciation, testimony and exhibits from the prior rate case, UNS Electric's application and testimony in the current case, UNS Electric's responses to data requests of Staff and other parties, Excel files supporting UNS Electric witness Ronald White's derivation of UNS Electric's depreciation rates, information provided to me by Staff, and other publicly available information.

Q. What Commission rules address the treatment of depreciation?

A. The Commission's rules at R14-02-102 address the treatment of depreciation. A copy of these rules are presented, for ease of reference, in Attachment RCS-3. The current version of the rules appear to have been adopted effective April 9, 1992. This pre-dates the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" which has resulted in revisions for financial reporting purposes, among other things, of the presentation of cost of removal information. I discuss SFAS No. 143 in more detail subsequently in my testimony.

Q. Did UNS Electric file a new depreciation study in the current rate case?

A. Yes. Exhibit REW-2 attached to Dr. White's testimony is the 2006 Depreciation Rate Study for UNS Electric, Inc.

Q. Please discuss the Company's proposed depreciation rates and how they were derived.

A. The new depreciation rates proposed by UNS Electric are summarized in Company witness Dr. White's testimony and are shown in detail in his Exhibit REW-2. The

Company's proposed rates were developed using a depreciation system composed of the straight-line method, broad group procedure and remaining life technique.

Q. What impact do the new depreciation rates proposed by UNS Electric have?

A. As summarized on page 10 of Dr. White's testimony, based on December 31, 2005 plant investment, the new depreciation rates proposed by UNS Electric decrease depreciation expense by $1,231,943 (from $15,761,231 at present rates to $14,529,288 at the Company's proposed rates). As described above, after correcting for an error in the depreciation study that is discussed in the Company's responses to data requests STF 3.39 and STF 11.8, the revised annual accrual is $14,385,991, and the annualized decrease in the depreciation accrual from existing rates is $1,375,240.

On a composite basis[8], after reflecting the error correction described in the responses to data requests STF 3.39 and STF 11.8, the Company's proposed new rates produce an decrease of 0.39 percentage points, from the current composite rate of 4.53% to a composite at new rates of 4.14%.

Q. Before discussing specific issues associated with UNS Electric's proposed depreciation rates, could you please provide your understanding of some basic depreciation terminology?

A. Yes, of course.

Q. What is depreciation?

A. The Commission's rules at R14-2-102(A)(3) define "depreciation" as "an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life."

[8] UNS Electric does not apply its depreciation rates on a composite basis; this information is for comparative purposes only.

Q. What is net salvage?

A. The Commission's rules at R14-2-102(A)(5) define "net salvage" as "the salvage value of property less the cost of removal."

Q. What is "salvage value"?

A. The Commission's rules at R14-2-102(A)(5) define "salvage value" as:

> "the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; or if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate accounts."

Q. What is the "cost of removal"?

A. The Commission's rules at R14-2-102(A)(5) define the "cost of removal" as "the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto."

Q. What is depreciation expense?

A. Depreciation expense is a charge to operating expense to reflect the recovery of depreciable utility plant. Depreciation rates are applied to a utility's depreciable utility plant to determine the amount of depreciation expense. Public utility depreciation expense is typically straight-line over the service life which results in an equal share of the cost of assets being assigned or allocated to expense each year over the service life of the assets. A service life is the period of time during which depreciable plant and equipment is in service. [9]

[9] National Association of Regulatory Utility Commissioners Public Utility Depreciation Practices, August, 1996. ("NARUC Depreciation Manual"), p. 321. Also, Commission Rule R14-2-102, which defines "service life" as "the period between the date an asset is first devoted to public service and the date of its retirement from service."

Q. What is depreciable utility plant?

A. Public utilities record their plant investment activity in the individual plant accounts set-forth in the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Plant additions, retirements and balances are maintained by plant account. An annual addition is the original cost of plant added to the account during the year. A retirement is recorded in the plant account by removing the original cost of a prior addition when such plant is removed from service. The plant balance is what is left at the end of an accounting period after accounting for additions and retirements.

Q. How is the annual depreciation expense calculated?

A. Annual depreciation expense, called an accrual, is calculated by applying a depreciation rate to plant balances.

Q. Is the depreciation accrual a cash expense?

A. No. Depreciation is considered a <u>non-cash</u> expense.

Q. Please explain the distinction between a cash and non-cash expense.

A. Depreciation expense is considered a non-cash accrual. This contrasts with payroll expense, for example, which involves the current outlay of cash. Depreciation expense does not involve a specific payment during the test-year. Both depreciation and payroll are included as expenses in the income statement and revenue requirement, but no cash flows out of the company for depreciation expense. Instead of reducing the cash account, depreciation expense is recorded on the income statement as an expense and is simultaneously recorded on the balance sheet in the accumulated depreciation account; which is shown as an offset to plant in service. The following accounting entries illustrate the difference:

		Amount
Account	Description	Dr. (Cr.)
403	Depreciation Expense	$ 1,000
108	Accumulated Depreciation	$ (1,000)
	To record depreciation	
various	Payroll Expense	$ 1,000
131	Cash	$ (1,000)
	To record payroll expense	

Q. What is the Accumulated Depreciation account?

A. Accumulated Depreciation, Account 108 in the USOA, is a record of the previously recorded depreciation expense. At any point in time, the accumulated depreciation account represents the net accumulated amount of the original cost of assets and net salvage that has been recovered to date. From a regulatory perspective, Accumulated Depreciation can be considered a measure of the depreciation recovered from ratepayers. Commission Rule R14-2-102 defines "accumulated depreciation" as "the sum of the annual provision for depreciation from the time that the asset is first devoted to public service."

Q. How does depreciation expense impact a utility's revenue requirement?

A. Annual depreciation expense is a cost that is included in a public utility's revenue requirement. Because public utilities tend to be capital intensive, depreciation expense can be a significant component of the utility's revenue requirement.

Q. What is the objective of depreciation expense?

A. From a regulatory perspective, the objective of public utility depreciation is straight-line capital recovery. This is accomplished by allocating the original cost of assets to expense over the lives of those assets through the application of depreciation rates to plant balances. Additionally, many state regulatory commissions, including the ACC, have

allowed utilities to recover through the commission-authorized depreciation rates, the utility's estimated future cost of removal, which is part of the net salvage component of the depreciation rates.

Q. Please illustrate how depreciation rates are developed.

A. The following calculation shows a straight-line whole-life depreciation rate assuming a 10-year average service life and a $1 million plant investment, and the whole life method. Each year the 10% depreciation rate would be applied to plant in service to produce an annual depreciation expense and an entry to accumulated depreciation:

Straight-Line Whole-Life Depreciation Rate
Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: 100% / 10 Years = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
1	$ 100,000	$ (100,000)
2	$ 100,000	$ (200,000)
3	$ 100,000	$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 1,000,000	

Q. What happens at the end of an asset's life under this scenario?

A. All things equal, at the end of 10 years, the plant balance will be 100% (or $1 million), and the accumulated depreciation balance will also be 100% (also $1 million). This equality is important to understanding issues relating to the cost of removal/negative net salvage.

Q. What is negative net salvage?

A. Negative net salvage is the difference between any salvage value and the cost of removal of the asset after completion of its service life. If the cost of removal exceeds the salvage amount, this produces negative net salvage. In this testimony I will use the terms negative net salvage and net cost of removal interchangeably. The ratemaking treatment of negative net salvage was raised by a Staff witness (Mr. Majoros) as a major issue affecting utility depreciation rates in a previous APS rate case, Docket No. E-01345A-03-0437. Negative net salvage can have a significant impact on a utility's depreciation rates and revenue requirement.

Q. What happens if estimated future negative net salvage is included in the calculation?

A. Assume a negative 55 percent (-55%) net salvage ratio. The above whole-life example with a 55% value for negative net salvage is as follows:

Straight-Line Whole-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [100% - (-55%)] / 10 Years = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
1	$ 100,000	$ (100,000)	$ 55,000	$ (55,000)
2	$ 100,000	$ (200,000)	$ 55,000	$ (110,000)
3	$ 100,000	$ (300,000)	$ 55,000	$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 1,000,000		$ 550,000	

In this example, negative net salvage increases the resulting whole-life depreciation rate from 10% to 15.5%, i.e., by 55%. This increase results from the inclusion of estimated future net cost of removal, including estimated future inflation.

Q. Please explain the "FAS 143 Regulatory Liability" column in the above example.

A. Because the Company has no current legal obligation to pay the estimated future inflated cost of removal (negative net salvage) amounts (i.e., has no asset retirement obligation), the excess amounts recovered through depreciation rates are accumulated in a regulatory liability account for financial reporting purposes, pursuant to Statement of Financial Accounting Standards No. 143. (SFAS 143) I will explain certain provisions in SFAS 143 that require such treatment in more detail later in my testimony.

Q. Why does negative net salvage increase the depreciation rate?

A. It increases the depreciation rate because negative salvage is, in effect, added to the original cost of the plant. Instead of 100% (which represents the original cost of assets), the numerator becomes 155%. This is equivalent to capitalizing or adding the estimated cost of removal to the original cost of the asset. In the above example, instead of recovering the original plant cost of $1 million, the depreciation rates would recover $1.55 million.

Q. What happens at the end of a plant asset's life under this scenario?

A. The plant balance will be 100% but the sum of the accumulated depreciation balance and the regulatory liability account will be 155%. Consequently, unlike the "zero net salvage scenario" shown above, when negative net salvage is included in a depreciation rate, there will not be an equality of plant and reserve at the end of an asset's life because the Company will have charged more depreciation than it paid for the original cost of the asset. Under these circumstances, equality will only be achieved if the Company actually spends additional money at the end of the asset's life.

Q. Is the Company required to pre-collect from ratepayers estimated future amounts of money that it might spend at the end of plant useful life?

A. Where there is no legal requirement to incur cost of removal, UNS Electric has no current legal liability to spend money for estimated future cost of removal, the Commission rules at R14-2-102(B)(3) require that: "The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systematic manner over the estimated service life of the plant." As discussed above, the Commission's rules define "net salvage" to include the cost of removal. Consequently, I conclude that the Commission's rules require cost of removal to be included in the utility's depreciation rates.

Q. If the Company does incur an obligation at the end of an asset's service life that requires spending money for removal, can the Company take the money out of accumulated depreciation?

A. No. Accumulated Depreciation is an unfunded account. Even though the Company collected money from ratepayers for future removal cost that had been included in past depreciation rates, it will have already spent that money on whatever it chose in the past: salaries, dividends, etc.

Q. Please explain the concept of remaining life depreciation.

A. The remaining life technique is similar to the whole-life technique, but it incorporates accumulated depreciation into the numerator of the equation, and the denominator becomes the remaining life rather that the whole life of the asset.

Q. What happens when accumulated depreciation is incorporated into the numerator of the basic depreciation calculation?

A. If the 10-year asset is 3 years old, its remaining life would be 7 years (10 – 3 = 7). The accumulated depreciation account would be 30% of the original cost because the 10% depreciation rate would have been applied for three years (3 x 10% = 30%). The remaining life depreciation rate would then be 10%, calculated as follows:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: [100% - 30%] / [10 - 3 Years] = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
3		$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 700,000	

Under the example with the assumed 55% negative net salvage, and a 7-year remaining life, the results would be a 15.5% depreciation rate, as shown below:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [(100% - (-55%)) - (3 x 15.5%)] / [10 - 3 Years] = 15.5% Per Year
Depreciation Rate: [(108.5%)] / [7 Years] = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
3		$ (300,000)		$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 700,000		$ 385,000	

Q. Why would the whole-life depreciation rate in the example with negative net salvage and the remaining life depreciation rate in the negative net salvage example both be 15.5 percent?

A. In these examples, the remaining life depreciation rate and the whole-life depreciation rates are the same (15.5 percent) because I have assumed that the accumulated depreciation account is in balance. In other words, based on a continuation of the fundamental parameters, i.e., the 10-year service life and the negative 55% net salvage ratio, exactly the right amount of depreciation has been charged and collected in the past.

Q. What would happen if either of these fundamental parameters were to change?

A. If either the service life or net salvage parameter changes during the life of the plant, the accumulated depreciation account will be out of balance, and the remaining life rate will be either higher or lower than the whole-life rate depending on the direction of the imbalance. That is because the Company will have collected either too much depreciation or not enough depreciation in the past, given the current estimates of lives or future net salvage. The difference between the actual amount recovered, as included in the book depreciation reserve, and a theoretical estimate of what should be in the book reserve, is called a "reserve imbalance." The remaining life technique is often used to deal with such reserve imbalances.

Q. Since the last revision to the Commission's rules regarding the treatment of depreciation, has a significant accounting pronouncement been issued?

A. Yes. As noted above, it appears that the Commission's rules concerning the treatment of depreciation were last revised and became effective April 9, 1992. Since that date, generally accepted accounting principles ("GAAP"), specifically SFAS 143, highlight the amounts associated with estimated future cost of removal for which no current legal

obligation exists and require that they be reported as Regulatory Liabilities for financial reporting purposes. A regulatory liability can be viewed as an amount owed to ratepayers.

Q. What is SFAS 143?

A. The Financial Accounting Standards Board ("FASB") is a standards-setting body for the public accounting profession. In June 2001, the FASB promulgated Statement of Financial Accounting Standards No. 143 (FAS 143). This pronouncement addresses the appropriate accounting for long-lived assets. It is effective for all fiscal years beginning after June 15, 2002. However, earlier application was encouraged. Pursuant to SFAS 143, all companies, both unregulated (e.g., Walmart) and regulated (e.g., UNS Electric) must review all of their long-lived assets to determine whether or not they have actual legal obligations to remove retired assets. For some plant and equipment, companies have a legal obligation to remove the asset at the end of the service life. These legal obligations for future removal are called asset retirement obligations ("AROs"). For other assets, no such obligation exists.

If a company does have an ARO, the fair value of the future retirement cost, which is determined using net present value techniques, is considered to be part of the original cost of the asset. That ARO is therefore capitalized (included in the original cost) and depreciated over the life of the asset. In essence, if a Company incurs a legal liability to spend money to remove an asset at the end of its life, that liability is part of the cost of the asset.

In contrast, if a company does <u>not</u> have such legal obligations, the future cost of removal will <u>not</u> be capitalized as part of the asset cost and will <u>not</u> be included in depreciation

expense. Only the initial cost of the asset (which does not include estimated inflated future cost of removal for which no current liability exists), will be depreciated.

At the end of the asset's life, for assets without AROs, the accumulated depreciation account will equal the plant balance. In other words, under SFAS 143, there is symmetry between assets with and without AROs. In both cases, the accumulated depreciation will equal the original cost of the asset at the end of its life.

Q. How are AROs measured?

A. AROs are measured at their net present value, not their inflated future value.

Q How are AROs recorded for accounting purposes?

A. As stated above, AROs are capitalized as a cost of the related asset and simultaneously recorded as a liability for those companies with a legal obligation to remove a retired asset. To illustrate, assuming an ARO of $500, the $500 would be debited (i.e., added) to plant and simultaneously credited (i.e., added) to the regulatory liability account. Each year, as the liability increases due to inflation, the increase is charged to accretion expense and credited to the liability, but the asset value remains the same. In other words, just as the original cost of the asset does not increase, neither does the capitalized asset retirement cost.

Q. What happens if a company does not have an asset retirement obligation pursuant to SFAS 143?

A. If a company does not have such obligations, the estimated future inflated cost of removal is not considered as a cost of the asset, and therefore it will not be included in the company's depreciation expense on its general purpose financial statements. SFAS 143,

therefore, unbundles net salvage from depreciation rates. It does this in two ways: (1) by incorporating the net present value of an ARO in the cost of the asset, or (2) by excluding non-AROs from the depreciation rate calculations.

Q. What is the accounting impact of SFAS 143 for electric utilities?

A. Under GAAP, electric utilities are required to review all of their assets to determine if they have any AROs. If a utility has any AROs, they are capitalized. Paragraph B73 of SFAS 143 provides an exception for regulated utilities, which allows them to continue to incorporate net salvage factors ("non-legal AROs") in depreciation rates even if they do not have AROs. Utilities are also required to determine the amount of any prior cost of removal collections relating to non- AROs that is now included in their accumulated depreciation accounts, and reclassify these and any such future charges as a regulatory liability in their financial statements. In other words, even with the paragraph B73 exception, SFAS 143 provides transparency through reporting disclosure requirements.

Q. What is the impact of SFAS 143 on electric regulatory accounting?

A. FERC addressed SFAS 143 in Docket RM02-7-000 which resulted in Order No. 631. FERC Order 631 essentially adopts SFAS 143 and integrates it into the Uniform System of Accounts. Utilities are required to review their long -lived assets to determine if they have any AROs. Where utilities do not have AROs, any charges for such amounts must be separately identified. FERC Order 631 defines cost of removal allowances for which there is no legal asset retirement obligation, as "non-legal retirement obligations." Past and future "non- legal AROs" must be specifically identified and accounted for separately in the depreciation studies, depreciation expense and the accumulated depreciation account. In Order 631, FERC maintains the transparency resulting from the "separation

principle" for non-legal AROs that was established in paragraph B73 of SFAS 143. Paragraph 38 of Order 631 explains FERC's new requirements for non-legal AROs:

> "Instead, we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. Therefore, the Commission is amending the instructions of accounts 108 and 110 in Parts 101, 201 and account 31, Accrued depreciation - Carrier property, in Part 352 to require jurisdictional entities to maintain separate subsidiary records for the purpose of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals."

Q. Does FERC provide any additional insight as to the interpretation of these new rules?

A. Yes, at paragraph 39 of the order, FERC states:

> "Jurisdictional entities must identify and quantify in separate subsidiary records the amounts, if any, of previous and current accumulated removal costs for other than legal retirement obligations recorded as part of the depreciation accrual in accounts 108 and 110 for public utilities and licensees, account 108 for natural gas companies, and account 31 for oil pipeline companies. If jurisdictional entities do not have the required records to separately identify such prior accruals for specific identifiable allowances collected in rates for non-legal asset retirement obligations recorded in accumulated depreciation, the Commission will require that the jurisdictional entities separately identify and quantify prospectively the amount of

current accruals for specific allowances collected in rates for non-legal retirement obligations."

Q. Does FERC make any policy calls concerning the appropriate treatment of the disposition of prior and future collections contained in these separate allowances?

A. No. As indicated at paragraph 64 of the Order, FERC declined to make such calls on a policy basis. Rather, FERC will resolve the appropriate treatment of the dispositions of prior and future collections on a case-by-case basis.

Q. Does FERC's Order require anything new or more with respect to its requirement for detailed depreciation studies?

A. No. At paragraph 65 of the Order, FERC states that:

> "... this rule requires nothing new and nothing more with respect to the requirement for a detailed study. Complex depreciation and negative salvage studies are routinely filed or otherwise made available for review in rate proceedings. When utilities perform depreciation studies, a certain amount of detail is expected. It is incumbent upon the utility to provide sufficient detail to support depreciation rates, cost of removal, and salvage estimates in rates."

Additionally, footnote 45 states:

> "When an electric utility files for a change in its jurisdictional rates, the Commission requires detailed studies in support of changes in annual depreciation rates if they are different from those supporting the utility's prior approved jurisdictional rate."

Thus, FERC recognizes distinctions between legal and non-legal AROs just as SFAS 143 recognizes those distinctions. On a going-forward basis, jurisdictional entities must be prepared to specifically identify and justify any non-legal AROs that they propose to include in rates.

Q. Has UNS Electric implemented SFAS 143?

A. Yes. The Company has implemented SFAS 143. Consistent with adopting this accounting principle for financial reporting purposes, UNS Electric reclassified prior year removal costs of approximately $1 million previously included in accumulated depreciation to the liability for asset retirements and removals in its Balance Sheets. As described on page 16 of the UNS Electric, Inc. Financial Statements for the Years Ended December 31, 2005 and 2004 (Exhibit KGK-1 to Ms. Kissinger's direct testimony): "UNS Electric had accrued $1 million at December 31, 2005 and $0.6 million at December 31, 2004, for the net cost of removal for interim retirements from its transmission, distribution and general plant. These amounts have been recorded as a regulatory liability."

When initially adopting SFAS 143, companies such as UNS Electric, reclassified for financial statement reporting purposes their accumulated cost of removal for which there is no current legal obligation for removal, from Accumulated Depreciation and reported this as a Regulatory Liability.

Q. Are the "costs of removal" that were reclassified as a regulatory liability for financial reporting purposes the result of UNS Electric's past depreciation rates?

A. Essentially, yes. Similar to most utilities, UNS Electric's past depreciation rates have included negative net salvage. This has resulted in UNS Electric pre-collecting from

ratepayers estimated future costs of removal for non-legal AROs, which under SFAS 143, have been reclassified for financial reporting purposes as a regulatory liability.

Plant and equipment are retired from service at the end of their useful lives. Sometimes the retired plant and equipment may be physically removed and can be resold for value. This is called gross salvage. The cost of removal net of the value received for the salvage constitutes net salvage. In more technical terms, gross salvage is the amount recorded for the property retired due to the sale, reimbursement, or reuse of the property. Cost of removal is the cost incurred in connection with the retirement from service and the disposition of depreciable plant. As discussed above, net salvage is the difference between gross salvage and cost of removal.

Q. Are net salvage ratios included in the Company's depreciation rate calculations?

A. Yes. Substantial negative net salvage ratios are included in several of UNS Electric's depreciation rates. The inclusion of negative future net salvage ratios in UNS Electric's proposed depreciation rates result in depreciation rates that are significantly higher in many instances than if no cost of removal had been included. As noted above, the inclusion of net salvage in depreciation rates appears to be consistent with past practices of the utility and Commission, and appears to be required by Commission rule R14-2-102(B)(3).

Q. Do UNS Electric's proposed depreciation rates include estimated future removal costs?

A. Yes. As noted above, UNS Electric's proposed depreciation rates include estimated future removal costs, including estimated future inflation. UNS Electric has done this by

including negative net salvage ratios in the development of depreciation rates for many, but not all, of its depreciable plant assets.

Q. Where does UNS Electric develop its estimated future cost of removal that are included in its proposed depreciation rates?

A. These are developed in Mr. White's Attachment REW-2, on Statement D (average net salvage), Statement E (present and proposed parameters) of those attachments.

Q. Did you request UNS Electric to provide its actual cost of removal and net salvage information by plant account?

A. Yes. This was requested in data request STF-3.30 for years 2000 through 2005.

Q. Did UNS Electric provide that requested information plant account?

A. UNS Electric provided the requested information only for calendar year 2005, but not for the other years. In response to STF 3.30, the Company stated that: "Please see the response to STF 3.19. Neither Foster Associates nor UNS Electric has actual cost of removal and net salvage information for calendar years other than 2005."

Q. Have you made a comparison of how much UNS Electric's proposed depreciation rates would collect annually for estimated future cost of removal with the Company's recent actual cost of removal?

A. No. During the course of my analysis, I started to make such a comparison, but concluded that it was not necessary for purposes of this case because the Commission's rules at R14-2-102 require net salvage to be included in the development of the utility's depreciation rates. Since I am not recommending an adjustment to reflect an alternative treatment of cost of removal in this case, the comparative calculation related to quantifying such an

adjustment was not pursued as it would have been if an adjustment to the Company's approach was being recommended.

Q. Has UNS Electric's approach to including net salvage in depreciation rates been widely used in the utility industry?

A. Yes. Many regulated utilities have used this approach. It is even addressed in the NARUC's 1996 Public Utilities Depreciation Practices Manual as a recommended approach. On the other hand, the same NARUC Manual at page 157 also states:

> "Some commissions have abandoned the above procedure [gross salvage and cost of removal reflected in depreciation rates] and moved to current-period accounting for gross salvage and/or cost of removal. In some jurisdictions gross salvage and cost of removal are accounted for as income and expense, respectively, when they are realized. Other jurisdictions consider only gross salvage in depreciation rates, with the cost of removal being expensed in the year incurred."

Q. In your opinion, is there a reasonable alternative to the approach used by UNS Electric?

A. Yes. Instead of incorporating estimated future cost of removal along with estimated future inflation into depreciation rates, providing a normalized level of removal cost as a current-period expense is a reasonable alternative for ratemaking purposes, in my opinion.

Q. Does the NARUC Manual indicate that some utility commissions are using this alternative approach?

A. Yes. The NARUC Manual at page 158 states that:

> It is frequently the case that net salvage for a class of property is negative, that is, cost of removal exceeds gross salvage. This circumstance has increasingly

become dominant over the past 20 to 30 years; in some cases negative net salvage even exceeds the original cost of plant. Today few utility plant categories experience positive net salvage; this means that most depreciation rates must be designed to recover more than the original cost of plant. The predominance of this circumstance is another reason why some utility commissions have switched to current period accounting for gross salvage and, particularly, cost of removal.

Q. Could UNS Electric's approach result in accumulated depreciation exceeding the original cost of plant in service?

A. Yes. One of the mechanical problems with UNS Electric's approach is that it can result in a depreciation reserve actually exceeding the gross plant balance. That is because the depreciation rates proposed by UNS Electric for distribution plant include estimated future cost of removal, and therefore produce higher depreciation rates than are necessary to fully depreciate the original cost of the plant. Therefore, at the end of its life, the accumulated depreciation account exceeds the plant account balance. Referring back to the hypothetical illustration that I presented earlier, with a 55% negative net salvage assumption, at the end of the 10-year assumed useful life, the utility has recorded $1.55 million in depreciation on a depreciable asset of $1 million. During the plant's depreciable life, the utility had no asset retirement obligation, but it would have collected an extra $550,000.

Q. How should the allowance for cost of removal be calculated?

A. Because the Commission's rules at R14-2-102 in their current form clearly require the inclusion of net salvage in the development of the utility's depreciation rates, and this is what UNS Electric has done, I am not in this proceeding recommending an alternative. Were it not for those rules, I believe there is substantial merit in the alternative

recommended by the witness for Staff in the prior APS rate case cited above, which would provide for a normalized allowance for cost of removal based on the average of the most recent five years worth of actual net salvage activity. Essentially, the cost of removal is treated just as any other normalized operating expense.

Q. Are you aware of whether other regulatory commissions use that alternative approach for utility recovery of cost of removal?

A. Yes. A five-year average net salvage allowance approach has been used for many years by the Pennsylvania Public Utility Commission. In recent years, some other state regulatory commissions have used similar approaches that exclude estimated future cost of removal from the development of depreciation rates, and provide an allowance for the cost of removal based on an average of a utility's actual incurred cost.

Q. What are the advantages of that approach?

A. The five-year rolling average for recovery of cost of removal provides a reasonable method for addressing this controversial aspect of depreciation. UNS Electric's proposed development of depreciation rates essentially treats estimated future costs of removal (including estimated future inflation) as a current period expense, even when there is no current legal obligation to incur such cost. In contrast with UNS Electric's approach, a normalized expense allowance approach better conforms with the generally accepted accounting principles articulated in SFAS 143 by not treating estimated inflated future removal costs as if they were a current obligation and a current expense. Additional advantages offered by the normalized expense allowance approach include that it is simple, straight-forward and easy to implement, provides an opportunity for the Company to recover a normalized allowance for cost of removal based on recent actual cost, and avoids charging current customers for estimated future inflation. However, the

Commission's rules at R14-2-102 in their present state would appear to preclude this alternative for purposes of this case.

Rule R14-2-102 is a rule of general applicability to electric utilities in the state of Arizona. Because I believe there is no compelling reason to treat cost of removal (where there is no current obligation to incur such cost) differently from other normalized operating expenses, I recommend that the Commission consider amending Rule R14-2-102 to allow treatment of cost of removal in the manner recommended by Staff's consultant in the prior APS rate case.

Q. Should the depreciation rates proposed by UNS Electric be adopted for use in this case, as corrected in the responses to data requests STF 3.39 and STF 11.8?

A. Yes. The depreciation rates proposed by UNS Electric presented in Dr. White's Attachment REW-2 should be adopted for use in this case, after reflecting the corrections described in the responses to data requests STF 3.39 and STF 11.8. The depreciation rates proposed by UNS Electric were developed in a manner that is generally consistent with the Commission's rules for depreciation rates. My review of the details provided in Dr. White's Attachment REW-2 and other information indicates that those new rates proposed by UNS Electric are consistent with industry accepted depreciation practices. As noted above in my testimony, the net change in percentage terms resulting from UNS Electric's proposed new depreciation rates in composite terms is fairly small, a decrease of 0.39 percentage points for UNS Electric plant.

Q. Do you have any other recommendations concerning the depreciation rates proposed by UNS Electric?

A. Yes. Each of the new depreciation rates proposed by UNS Electric should be clearly broken out between (1) a service life rate and (2) a net salvage rate. By doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

VI. CHANGES TO PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

Q. What revisions to its PPFAC has UNS Electric proposed that you are addressing?

A. I am addressing the revisions to the PPFAC described primarily in the direct testimony of UNS Electric witnesses Pignatelli at pages 8-14, and DeConcini at pages 15-21. As summarized by Mr. Pignatelli on page 9 of his direct testimony and Mr. DeConcini on pages 16-21, UNS Electric is requesting the following modifications to the PPFAC mechanism:

1. A clarification of the costs that can be included in the PPFAC. UNS Electric proposes that all costs included in FERC accounts 501, 547, 555 and 565 be included in the PPFAC.
2. UNS Electric also seeks to recover the cost of credit support associated with fuel and purchased power procurement and hedging through the PPFAC.
3. A new cost recovery mechanism to automatically adjust the PPFAC rate based on a 12-month rolling average cost of purchased power and fuel (including a "phase in" provision).
4. The recognition of carrying costs on the PPFAC bank balances at an interest rate equal to the LIBOR rate plus 1 percent.

5. A Bank Threshold of $10 million with an automatically instated surcharge or credit to return the balance over the next twelve months, accompanied by an informational filing from the Company detailing the calculation.

Q. Why is UNS Electric requesting these PPFAC revisions?

A. As described in the direct testimony of UNS Electric witnesses Pignatelli (page 10) and DeConcini (pages 1-2 and 15-21), the Company is requesting these changes due to the addition of new resources and contracts to replace the existing Power Supply Agreement ("PSA") with Pinnacle West Capital Corporation ("PWCC"). As described by Mr. DeConcini on page 2 of his direct testimony:

> "I have proposed a new PPFAC that also will become effective on the date the PWCC PSA expires. The current UNS Electric PPFAC rate is fixed and is tied to the PWCC PSA costs. When the PWCC PSA expires, UNS Electric will need a PPFAC that will accurately reflect UNS Electric's procurement of wholesale power and fuel. The proposed PPFAC would be based on the elements typically underlying recently approved PPFACs and would include a 12-month rolling average cost of power supply as the basis for retail pricing adjustments."

Q. Is UNS Electric also proposing rate design changes related to the shifting of power supply costs from the PPFAC to base rates?

A. Yes. UNS Electric witness Erdwurm's direct testimony at page 21 proposes to increase the base rate power supply to "slightly more than" 7 cents per kWh, to reflect the current base power supply rate of approximately 5.2 cents per kWh plus the approximately 1.8 cents per kWh currently recovered by UNS Electric from customers through the PPFAC. UNS Electric proposes to reduce the PPFAC rate to zero until June 2008 when the PWCC

PSA expires. The Company states that the new PPFAC it proposes would go into effect upon the expiration of the PWCC PSA.

Q. Are you addressing such rate design aspects of UNS Electric's PPFAC-related proposals in this testimony?

A. No. As provided for in the Commission's Scheduling Order, Staff will address such rate design aspects of the Company's PPFAC in the Staff rate design testimony to be filed on July 12, 2007.

Q. As guidance for your review of UNS Electric's proposed PPFAC changes, did you review material in any other recent proceedings involving Arizona electric utility adjustment mechanisms related to the recovery of fuel and purchased power costs?

A. Yes. I reviewed material filed by Staff in the recent Arizona Public Service Company rate case, Docket No. E-01345A-05-816, concerning fuel and purchased power recovery mechanisms, including the Staff's proposed Plan of Administration for a revised APS Power Supply Adjustment Mechanism ("PSA") that was filed with Staff witness John Antonuk's supplemental testimony in that docket, and subsequently underwent further revisions. In that case, Staff undertook a detailed review and made recommended revisions to the APS PSA. There are clearly differences between APS and UNS Electric, including: APS is a much larger utility, APS owns substantial generating resources, including steam, nuclear and other production, and APS makes off-system sales. In contrast, historically UNS Electric has not owned large generating resources, but has purchased most of its power needs from others, such as under the current power supply agreement that UNS Electric has with PWCC. Despite such differences, I believe that the Staff evaluation of the APS PSA in that case and the related Staff recommendations and Commission determinations relating to the APS PSA can provide helpful guidance in

reviewing the UNS Electric PPFAC in the current case. I will be referring to the latest available written iteration of the Plan of Administration that Staff developed for the APS PSA in my testimony and have attached a copy of it in Attachment RCS-4. I should note that this version of the Plan of Administration does not yet reflect the Commission's determinations in Docket No. E-01345A-05-0816 concerning the 90/10 sharing or the 4 mil per kWh annual cap, which I understand the Commission has retained in the APS PSA that was recently approved.

Q. Please describe the primary features of the current power supply agreement that UNS Electric has with PWCC.

A. UNS Electric currently has a full-requirements power supply agreement with PWCC ("PWCC PSA") that began on June 1, 2001 and expires on May 31, 2008. The PWCC PSA provides all energy and ancillary services to serve UNS Electric's entire load requirements at a fixed price per MWh.

Q. How will UNS Electric's power procurement change upon expiration of the PWCC PSA?

A. UNS Electric states in its direct testimony that it has developed a Procurement Plan which provides for a mix of market power purchases, resource acquisitions and contracts to provide the necessary capacity, energy, and reserves to reliably meet its load requirements after the PWCC PSA expires on May 31, 2008. Mr. DeConcini's direct testimony at pages 4-6 and his Confidential Exhibit MJD-2 provide a high level overview of the plan.

Q. Please discuss UNS Electric's current PPFAC.

A. The current UNS Electric PPFAC rate was set in Commission Decision No. 66028 (July 3, 2003), which approved the acquisition of the Citizens assets. The current PPFAC of

$0.01825/kWh was approved in Decision No. 66028 and reflects the fixed energy price under the PWCC PSA. The PPFAC provides an adjustment mechanism under which UNS Electric is allowed to pass through to customers purchased power and fuel cost increases and/or savings relative to a base power supply rate, via a surcharge or credit. The Company's current base power supply rate is $0.05194/kWh and was established in Decision No. 59951 (January 3, 1997).

The current PPFAC functions in the following manner. The Company's actual fuel and purchased power costs (excluding demand charges) are charged to a PPFAC Bank Balance. The sum of the base power supply rate plus any PPFAC rate are multiplied by energy consumption. The product of that multiplication, indicating the Company's recovery of fuel and purchased power costs, is subtracted from the PPFAC bank balance. When the PPFAC bank balance reaches a predetermined threshold, UNS Electric must make a filing with the Commission to propose a method to recover or return the bank balance. The current PPFAC cannot be changed without Commission approval.

Q. Does Staff agree with the Company's proposed new PPFAC?

A. No. While Staff agrees with some aspects of the Company's proposed changes to the current PPFAC, the changes proposed by UNS Electric, taken as a whole, would appear to result in inclusion of additional costs in the PPFAC, such as expenses for credit support, that have not been demonstrated to possess the characteristics of being material, volatile, and not within the Company's control. Additionally, by replacing provisions which currently require Commission review with automatic rate adjustment provisions, the Company's proposed new PPFAC could substantially reduce the level of regulatory scrutiny of purchased power and fuel costs. Such changes would seem to be particularly inappropriate at a time when the Company is transitioning from a full requirements

contract with fixed pricing provisions to a new procurement environment after May 2008 when the current PPWC PSA expires. Especially in such an environment, Staff believes that there should be Commission review of changes in PPFAC rates before they become applicable.

Q. The Company has proposed that the PPFAC include all costs that are recorded in FERC accounts 501, 547, 555 and 565. Can you briefly summarize what expenses are recorded in each of these accounts?

A. Yes. I do note that Mr. DeConcini presents a very high level description of what costs are included in each of these accounts at page 17 of his direct testimony.

Account 501, Fuel (Steam), includes the cost of fuel used in the production of steam for the generation of electricity, including fuel handling.

Account 547, Fuel (Other Production), includes the cost of fuel (such as gas, oil, kerosene and gasoline) delivered to the station for other power generation.

Account 555, Purchased Power, includes the cost of electricity purchased for resale. As described in the FERC Uniform System of Accounts for Electric Utilities[10]:

> "A. This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, spinning reserve capacity, etc. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, capacity, etc.,

[10] Code of Federal Regulations, Title 18, Volume 1, Part 101, Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, Revised as of April 1, 1999.

Distinct purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.

"B. The records supporting this account shall show, by months, the demands and demand charges, kilowatt-hours and prices thereof under each purchase contract and the charges and credits under each exchange or power pooling contract."

Account 565, Transmission of Electricity by Others, includes amounts payable to others for the transmission of the utility's electricity over transmission facilities owned by others.

Q. Has UNS Electric had fuel expense which it recorded in FERC accounts 501 or 547?

A. Staff understands that UNS Electric has incurred some fuel expense. However, a review of UNS Electric's operating expense information filed with its FERC Form 1 for calendar years, 2004 through 2006, indicates that the Company did not record any fuel expense in these accounts. Under the full-requirements contract with PWCC, the expense for purchased power has been recorded in Account 555.

Q. How do the FERC accounts that UNS Electric proposes to include in its PPFAC correspond with the FERC accounts that were included in Staff's proposed Plan of Administration for the APS PSA?

A. The FERC Accounts 501, 547, 555 and 565 that UNS Electric proposes to include in its PPFAC are basically the same accounts that Staff's proposed Plan of Administration includes for recovery by APS under the APS PSA. Page 15 of that Plan of Administration lists the accounts included for the APS PSA as these four FERC accounts, and, for APS,

also Account 518, Nuclear Fuel. UNS Electric does not have any nuclear generation and does not record expense in Account 518.

Page 15 of the Staff proposed Plan of Administration for the APS PSA also specifies that: "Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA." I believe that allowing UNS Electric to recover prudent direct costs of contracts it uses for hedging system fuel and purchased power under its PPFAC would also be appropriate.

Q. Do you have any concerns regarding UNS Electric's proposal that the PPFAC should include all expenses in FERC accounts 501, 547, 555 and 565?

A. Yes. I have the following concerns regarding capacity costs that may be recorded in Accounts 555 and 565:

Account 555 can include capacity and demand charges. Including such capacity and demand charges in a PPFAC that is recovered on a per kWh basis presents a concern. Additionally, it is fairly common, in my experience, for PPFAC-type mechanisms to include purchased energy expenses, and to exclude capacity costs from the PPFAC but to provide for recovery of a normalized level of purchased capacity costs in the utility's base rates.

Account 565, Transmission of Electricity by Others, may also have a capacity or demand element, depending upon the particular contracts the utility enters into for transmission service.

Q. Why do you have a concern regarding the recovery of capacity costs that may be recorded in Accounts 555 and 565 in the PPFAC?

A. There are two primary bases for such concerns. First, UNS Electric has not demonstrated that capacity costs that may be recorded in Accounts 555 and 565 are volatile, material and beyond the control of utility management. Moreover, in situations where the electric utility owns the generating capacity or transmission, the traditional ratemaking treatment has been to include the cost of such capacity, as measured in a test year, in the determination of a utility's base rate revenue requirement. Allowing purchased capacity costs to be recovered in a PPFAC mechanism, where owned capacity is recovered in base rates, could result in management decision making favoring purchased capacity that would be recorded in Account 555, rather than owning capacity resources that would be recorded as plant assets and would be subject to rate base treatment.

Second, the PPFAC rate would apparently be applied to each customer's bill as a monthly per kWh charge that is the same for all customer classes. There are concerns that a uniform per-kWh charge for all customer classes might not be appropriate for capacity-related charges. Staff's rate design testimony to be filed on July 12, 2007 may present additional details concerning capacity cost recovery.

Q. Have you examined the historical volatility of UNS Electric's expenses in each of the four FERC accounts 501, 547, 555 and 565?

A. Yes. The following summary of annual expenses in each of these four accounts for 2004 through 2006 was compiled from FERC Form 1 information:

UNS Electric's Recorded Expenses in FERC Accounts
Proposed by the Company for Recovery Through a PPFAC Mechanism

Account	2004	2005	2006
501	$ -	$ -	$ -
547	$ -	$ -	$ -
555	$ 96,467,281	$ 100,300,283	$ 106,271,505
565	$ 6,388,498	$ 6,631,327	$ 7,026,755
TOTAL	$ 102,857,783	$ 106,933,615	$ 113,300,266

Source for expense account information: UNS Electric FERC Form 1

Annual Change ($)

555		$ 3,833,002	$ 5,971,222
565		$ 242,829	$ 395,428
TOTAL		$ 4,075,832	$ 6,366,651

Annual Change (%)

555		4.0%	6.0%
565		3.8%	6.0%
TOTAL		4.0%	6.0%

This information suggests that historically UNS Electric's purchased power expense in Account 555 and transmission of electricity by others in Account 565 are significant and material to the Company's operations, but have not been particularly volatile. However, the historical lack of volatility has most likely been enabled by the full requirements arrangement that UNS Electric has had under the PWCC PSA, which is scheduled to expire on May 31, 2008. From June 2008 forward, UNS Electric's purchased power costs are likely to be subject to a higher degree of fluctuation than they have historically been under the full requirements PWCC PSA.

Q. Please discuss UNS Electric's proposal for including the "cost of credit support associated with fuel and purchased power procurement and hedging" be included in the PPFAC.

A. Mr. DeConcini states at pages 17-18 of his direct testimony that: "Prepayments, cash escrow accounts, standby letters of credit and parental guarantees are all common forms of credit support" in the wholesale markets for fuel and purchased power, and that UNS Electric wants to include in the PPFAC "the costs associated with standby letters of credit, prepayments, cash escrow accounts and parent guarantees." UNS Electric proposes to charge to the PPFAC bank balance a cost for standby letters of credit at an annualized cost equal to 1.0 percent of the face amount issued. UNS Electric also proposes to charge the PPFAC bank balance for prepayments and cash escrow accounts at UNS Electric's cost of short term borrowing. Additionally, UNS Electric proposes to charge to the PPFAC bank balance for parental guarantees "at the same rate charged to UNS Electric for letters of credit issued under the UNS Electric credit facility."

Q. Do you agree with UNS Electric's proposal that "cost of credit support associated with fuel and purchased power procurement and hedging" be included in the PPFAC?

A. No. UNS Electric has not demonstrated that inclusion of such costs in a PPFAC mechanism is reasonable or appropriate, is a common practice in the electric utility industry, or that such costs would be appropriately recorded in one of the FERC accounts that the Company proposes as the basis for its PPFAC. Prepayments and the cash working capital requirement associated with fuel and purchased power are reflected in the determination of base rates as a component of the utility's rate base. The cost of financing rate base components is reflected in the determination of the utility's base rate revenue requirement. Staff recommends that UNS Electric's proposal for including the "cost of

credit support associated with fuel and purchased power procurement and hedging" in the PPFAC be rejected.

Q. Please comment regarding the Company's proposal for basing the PPFAC on a 12-month rolling average cost of fuel and purchased power, including a "phase in" period.

A. This provision is not objectionable in itself; however, the Company's related proposal that the PPFAC rate changes are implemented **automatically** is not favored by Staff, especially at a time when UNS Electric's fuel and purchased power procurement would be undergoing significant changes, and may thus be deserving of a higher level of regulatory scrutiny. Also, the provision for changing PPFAC rates monthly is not favored because very frequent rate changes could increase customer confusion and cause negative customer reactions.

Q. What is your understanding of why UNS Electric has proposed the use of a rolling 12-month average?

A. At page 19 of his direct testimony, Mr. DeConcini states that the Company is requesting a 12-month rolling average because it provides a level of price smoothing to customers to help mitigate extreme price changes that may be only short term in nature. He also states that current Purchased Gas Adjuster Mechanisms for UNS Gas and Southwest Gas Corporation both have a 12-month rolling average auto-adjusting feature.

Q. What concerns were expressed by Staff concerning the use of a rolling average to set power supply adjustment rates in the recent APS rate case?

A. In the recent APS rate case, Staff recognized that the main advantage of a "rolling average" approach is that it would smooth out the cost discontinuities produced in very

volatile energy markets, and is therefore responsive to the issue of managing volatility. However, when addressing the rolling average issue in the recent APS case, Staff had two concerns: (1) that such an approach could actually increase deferrals, and (2) that very frequent rate changes could increase customer confusion and cause negative customer reactions.[11]

Q. In the APS rate case, did Staff recommend an alternative to the use of a rolling average approach?

A. Yes. In the APS rate case, Staff recommended a Plan of Administration designed to provide for the recovery of actual, prudently incurred fuel and purchased power costs, based on three components: (1) a forward component (based on forecast fuel and purchased power costs), (2) an historical component (which tracks the differences between actual and recovered costs), and (3) a transition component (which provides for recovery of balances arising under the provisions of the previous power supply recovery mechanism). The details of Staff's proposal in the APS case are more fully presented in the Plan of Administration, that I have presented for ease of reference in Attachment RCS-4.[12]

Q. Does Staff suggest that an alternative arrangement for a UNS Electric PPFAC that combined similar elements?

A. Yes. While the specific details would need to be tailored to UNS Electric's particular situation, Staff believes that a new PPFAC mechanism for UNS Electric that contains many of the same elements in the APS PSA Plan of Administration could be workable, and could provide benefits to UNS Electric and its ratepayers.

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[11] See, e.g., Docket No., E-01345A-05-0816, Supplemental Testimony of John Antonuk, at pages 23-24.

[12] As noted above in my testimony, this attachment is the most current iteration of the Plant of Administration for the APS PSA and does not yet reflect or incorporate the Commission's determinations in the APS rate case regarding the 90/10 sharing or the 4 mills per kWh annual bandwidth provisions.

Q. Do you agree with UNS Electric's proposal for recognition of carrying costs on the PPFAC bank balances?

A. I agree in general that providing for carrying costs on deferred PPFAC bank balances prospectively would be appropriate.

Q. What interest rate should be applied to the monthly PPFAC bank balance?

A. Staff recommends using an interest rate, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, applied each month to the previous month's balance. This is essentially the same recommendation for the carrying cost rate that Staff proposed in the APS PSA Plan of Administration.[13] The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the customer deposit rate.

Q. How does the carrying cost rate Staff recommends compare with UNS Electric's proposed interest rate for customer deposits?

A. As shown on Exhibit TJF-1 to Direct Testimony of Thomas J. Ferry, in the red-lined version of the Rules and Regulations, page 16 of 109, section 3, UNS Electric has proposed in its rate case to use the one-year Treasury constant maturities rate for customer deposits. This is the same interest rate that Staff recommends be applied to compute carrying charges on the monthly PPFAC bank balances.

[13] See, e.g., Attachment RCS-4, pages 10, 11 and 13 of the Staff Proposed Plan of Administration.

Q. Please comment regarding the Company's proposal for increasing the PPFAC bank balance threshold to $10 million, with an automatically instated surcharge or credit to return the balance over the next twelve months.

A. The $10 million threshold is not objectionable, taken by itself. Mr. DeConcini states, on page 20, that the Company's proposed new threshold level of $10 million was calculated as 10 percent of test year fuel and purchased power costs and rounded to the nearest million dollars. Mr. DeConcini also indicates that this higher level will mitigate the need for frequent filings that might otherwise occur due to short-term changes in fuel and purchased power prices.

Staff does not object to the proposal by UNS Electric that a PPFAC bank balance exceeding $10 million should trigger a filing. However, Staff recommends that the filing be more than informational, that the period over which the bank balance is amortized into rates be left to the discretion of the Commission rather than be pre-mandated at 12 months, and that the surcharge not automatically become effective without Commission approval.

I also note that if a new PPFAC for UNS Electric is adopted that is similar to the APS PSA Plan of Administration, but tailored to UNS Electric's circumstances, this would provide for an appropriate filing and review process, and would avoid automatic rate changes occurring without Commission approval.

Q. What kinds of filing and reporting should be required for UNS Electric's new PPFAC mechanism?

A. Staff recommends that filing and reporting be required for a new UNS Electric PPFAC mechanism similar to those set forth in the APS PSA Plan of Administration, with such

elements as the annual reporting period and specific information to be filed being appropriately tailored to fit UNS Electric's situation.

Q. What effective date does UNS Electric propose for a new PPFAC mechanism?

A. As stated on page 19 of Mr. DeConcini's direct testimony, UNS Electric proposes that the new PPFAC Mechanism begin June 1, 2008 upon the expiration of the PWCC PSA.

Q. Does Staff agree that a new PPFAC mechanism for UNS Electric should begin June 1, 2008?

A. Yes. While Staff does not agree with the specific new PPFAC mechanism that has been proposed by UNS Electric, and would prefer to see a new PPFAC mechanism for UNS Electric that more closely corresponds with the provisions of the APS PSA Plan of Administration, Staff does agree that it would be appropriate for a new PPFAC to begin June 1, 2008, to correspond with the expiration of the PWCC PSA.

Q. Has the Company proposed a phase-in period for its new PPFAC?

A. Yes. Mr. DeConcini's direct testimony at pages 19-20 describes the Company's proposed phase-in period, which would be applicable for the first six months after implementation of the mechanism beginning June 1, 2008.

Q. Does Staff agree with the Company's proposed phase-in?

A. No. Staff would prefer to have the new PPFAC for UNS Electric based on the three components (forward, historical and transition) that Staff recently recommended for the APS PSA Plan of Administration. The combination of the historical and transition components, which would need to be tailored to fit UNS Electric's particular

circumstances, is believed to be sufficient to address issues related to transitioning from the Company's old PPFAC to a new PPFAC.

Q. What principal features should be considered in the design or modification of UNS Electric's fuel and purchased power adjustment mechanism?

A. The following features should be considered:

- There should be Commission review of proposed charges before they become applicable. The Company's current PPFAC already does this by requiring Commission approval of any PPFAC rate changes before they are implemented. The Company's proposed new PPFAC would eliminate this provision by providing for automatic rate changes to occur without Commission review of proposed charges before they become applicable.
- There should be a clear provision for the reconciliation of revenues and costs. The current PPFAC provides for a type of reconciliation in the PPFAC bank balance accounting, whereby fuel and purchased power expenses are matched with the base rate power supply and PPFAC revenues under which the Company recovers such costs.
- There should be an opportunity for an independent Commission review of prudence and reasonableness in all areas that drive the costs collected under the PPFAC. The content of these reviews and the issues they address should be subject to examination and comment by the affected stakeholders. The ultimate purpose of such reviews is to enable the Commission to make an informed determination of what, if any, costs resulted from ineffective or imprudent utility performance, and what, if any, adjustments should be made to future recoveries and over what periods of time.
- The PPFAC should provide a reliable mechanism for assuring reasonably prompt recovery of prudent and reasonable fuel and energy costs. Ideally, a well designed

PPFAC would avoid situations where delayed recovery of prudent and reasonable fuel and energy costs would have material financial consequences (e.g., through increased financing costs or restraints on access to financial resources). Put another way, the PPFAC should, by providing for reasonably prompt recovery of prudent and reasonable fuel and energy costs, help to maintain the utility's financial benchmarks that promote the ability to secure financing at costs favorable to customers.

Q. Are there any other considerations?

A. Yes. The Commission may want to include a provision designed to provide the utility with an incentive to procure fuel and purchased power at the lowest cost consistent with providing reliable electric service might be appropriate, although such provisions can be difficult to design in terms of providing the appropriate balance between facilitating recovery of prudently incurred costs and structuring the incentives.

Q. Please summarize your recommendations concerning the development of a new PPFAC mechanism for UNS Electric.

A. The new PPFAC proposed by UNS Electric contains objectionable features such as automatically adjusting rates without Commission approval and inclusion of costs that would more appropriately be addressed in base rates, as well as raising other concerns, and should therefore be rejected. A new PPFAC for UNS Electric should be developed along the lines of the APS PSA Plan of Administration Staff proposed for the Arizona Public Service Company in Docket Nos., E-01345A-05-0816 et al, after appropriate adjustments to fit UNS Electric's circumstances. The new PPFAC for UNS Electric should become effective June 1, 2008, upon expiration of the Company's all requirements power contract with PWCC.

VII. COMPANY'S PROPOSED RATEMAKING TREATMENT FOR A NEW PEAKING UNIT, BLACK MOUNTAIN GENERATING STATION

Q. What is the Black Mountain Generating Station ("BMGS")?

A. The BMGS is a 90 MW peaking facility under development at a site in Mohave County. BMGS consists of two LM 6000 combustion turbines. It is being developed by an affiliated company, UniSource Energy Development Company ("UEDC"). UNS Electric witness Kevin Larson states (at pages 2 and 4 of his direct testimony) that UEDC has negotiated a turnkey construction contract for the project totaling $46 million. UEDC is in the process of obtaining permits and making other arrangements to meet a projected operating date of May 2008. The Company estimates additional costs of permitting, site improvements, obtaining water supply, connecting to a gas pipeline, making substation improvements, providing project supervision and paying interest on borrowed funds of $14 million to $19 million. In total, UNS Electric estimates BMGS will cost $60 to $65 million.

Q. What ratemaking treatment is the Company requesting for BMGS?

A. UNS Electric requests that the Commission include the BMGS in its rate base effective as of June 1, 2008 as set forth in the testimony of Company witness Kevin Larson. Specifically, as explained on page 3 of Mr. Larson's direct testimony: "the Company is requesting a post-test year adjustment to rate base and a corresponding reclassification of rates effective June 1, 2008, or at a later date if commercial operation is delayed beyond June 1, 2008." The Company's proposed post-test year adjustment would add approximately $10 million to the non-fuel (base rate) revenue requirement, assuming a $60 million completion cost. As Mr. Larson further explains (on page 3 of his direct testimony): "On the effective date of this adjustment, UNS Electric would increase the average base delivery charge to customers by approximately 0.6 cents per kWh, and make

a corresponding decrease of 0.6 cents per kWh to the base power supply rate." He states that, initially, this proposal will be "revenue neutral" to UNS Electric. Other features of the Company's proposed ratemaking treatment for BMGS include (per Mr. Larson's direct testimony, at page 4):

- If actual project costs exceed $60 million, UNS Electric will not seek rate base treatment of any cost difference until the Company's next rate case.
- Following the purchase of the project by UNS Electric and upon commercial operation of the facility, the Company would provide the Commission with a project completion report, detailing the cost of completion and the results of pre-commercial testing.
- Thirty days after such report is filed, or on June 1, 2008 if the project is completed prior to May 1, 2008, the Company would implement the rate reclassification described above.

Q. What has the Company said it would do if the Commission rejects its proposal for a post-test year adjustment to rate base?

A. At page 5 of his direct testimony, Mr. Larson states that UNS Electric could elect to enter into a purchased power agreement ("PPA") with its affiliate, UEDC. He states that the terms of the PPA would be subject to approval by the Commission and by FERC.

Q. What costs of BMGS have been incurred by UNS Electric?

A. It appears that only minimal, if any, costs have been incurred by UNS Electric in the test year. As of the end of the test year, it appears the Company had not incurred any cost for BMGS construction. The response to STF 11.2 states that none of the Company's end-of-test-year CWIP balance includes BMGS cost. Additionally, Staff's engineering report, which reported on the results of a site visit made in June 2007 among other things, revealed very little work has apparently been done at the plant site. It appears that costs related to BMGS construction are being recorded on the books of the affiliate, UEDC, rather than on UNS Electric's books.

Q. What concerns regarding regulatory lag has UNS Electric expressed related to BMGS?

A. Pages 7-8 of Mr. Larson's testimony expresses concern that the time lag between construction outlays, commercial operation and rate recognition of new generating facilities can be quite long if a post-test year adjustment to rate base is not allowed. He estimates that, since the units are not scheduled for completion until the second quarter of 2008, a test year ending June 30, 2008 would have to be used in order to get the full cost of these units into rates on an historical test year basis. He estimates that new rates reflecting the full cost of the peaking unit would not become effective until January 2010. He states that, "from a financial perspective, UNS Electric cannot wait until 2010 for rate recovery on a project of this size." Finally, he states that, "in light of this potential outcome, as well as the borrowing constraints faced by UNS Electric, a decision was made to develop the peaking facility project at UEDC."

Q. Does the Company's proposed treatment of BMGS appear to qualify as a post-test year adjustment in the current rate case?

A. No, it does not. There are several concerns with approving rate base treatment of BMGS in the current rate case, including the uncertainties relating to the plant. One of the primary deficiencies is that the plant is not expected to be in commercial operation until May or June of 2008. This is well beyond the end of the test year in the current UNS Electric rate case, and is several months beyond even the scheduled hearing. Additionally, there is uncertainty regarding the total cost of the plant. There is uncertainty regarding whether the ownership of the plant would be at the utility, UNS Electric, or with the affiliate, UEDC. There is uncertainty regarding whether it would be more economical for UNS Electric and its ratepayers for the utility to own the plant or to obtain power by some other means. Given the substantial uncertainties regarding BMGS, Staff believes it would be premature and inappropriate to approve the Company's request for rate base inclusion.

Q. Although you believe that the BMGS does not qualify as a post-test year adjustment to rate base in the current rate case, is Staff sympathetic to the need for potentially providing some type of extraordinary ratemaking support for this plant, given the size of the project in relation to UNS Electric's existing rate base?

A. Yes. Staff understands that the cost of BMGS, if it is to be acquired by UNS Electric, would result in a significant increase in the Company's rate base. Staff is somewhat sympathetic to the Company's related concerns about providing a supportive regulatory treatment relating to the financing. Staff witness Alexander Igwe is addressing the Company's request for approval of issuing additional financing, and, as described in his testimony, Staff is supportive of that request, subject to certain safeguards.

Q. What does Staff recommend?

A. Staff recommends that the Commission deny the Company's requested rate base and ratemaking treatment of BMGS. Staff recommends that the Company apply for an accounting order requesting permission to defer costs related to BMGS from the date of the later of UNS Electric ownership or BMGS commercial operation until the unit is recognized in rate base in the Company's next rate case. Deferred accounting treatment would protect the Company's earnings until a new rate case could be filed and processed. This treatment would also enable an analysis of the various options once the total cost of BMGS is known.

Q. At page 4 of his direct testimony, Mr. Larson states that UNS Electric considered such an alternative, but it would not enable the Company to raise the capital necessary to purchase the facility, and would not provide the cash flow necessary to support an additional $60 million to $65 million of capital during the cost deferral period. Please respond.

A. A number of considerations lead Staff to conclude that an accounting order would be preferable to granting UNS Electric the post-test year rate base adjustment the Company has requested in this proceeding. There are presently too many uncertainties concerning BMGS to warrant granting the post test year rate base treatment requested by the Company. The uncertainties and other factors are such that granting the Company a post-test year rate base adjustment for this plant in the current rate case would be inappropriate.

First, the cost and commercial operation date of BMGS is not yet known with certainty.

Second, the Company's anticipated in-service date is well beyond the end of the June 30, 2006 test year being utilized in the current rate case.

Third, an accounting order granting deferral would protect the Company's earnings during the period before the plant received rate recognition.

Fourth, in terms of raising capital, it is unclear to Staff how UNS Electric would be unable to raise the capital to purchase the facility when an affiliated company, UEDC, could raise the capital to construct the plant and potentially finance it for use in a future purchase power agreement, for which key specifics, such as pricing and contract duration are currently unknown. As I have noted above, Staff witness Alexander Igwe has recommended approval of UNS Electric's requested financing.

Fifth, it not known whether having UNS Electric purchase a peaking unit such as BMGS is the most economical alternative to obtain power for the short, intermediate or long-term.

Sixth, in terms of the impact on cash flow, the Company's proposal is to have BMGS included in rate base by a "revenue neutral" rate reclassification that apparently would not result in any net rate adjustment. It is unclear how the Company's proposed "revenue neutral" rate reclassification would result in a substantial improvement in the Company's cash flow if it were to be implemented in a truly "revenue neutral" manner that did not result in a substantial net rate increase.

Q. Should the ratemaking treatment of BMGS and the Company's related concerns about cash flow and regulatory lag issues related to BMGS be addressed in the context of UNS Electric's next rate case?

A. Yes. Staff believes the ultimate rate base and ratemaking treatment of BMGS would best be determined in UNS Electric's next rate case.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, PSC staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Washington, Washington, D.C., Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed was the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)

U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. - Partial and Immediate (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-7650	Consumers Power Company – Final (Michigan PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)

R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU	
& 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
R-860378	Duquesne Light Company Surrebuttal (Pennsylvania PUC)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities
T E-1032-88-102	Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona
& U-1551-89-103	Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and	Intrastate Access Charge Methodology, Pool and Rates
TC-91-040B	Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS &	General Development Utilities - Port Malabar and
911-67-WS	West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)

R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)

PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)

Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016,	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
Phase I	
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020	
Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)

Attachment RCS-2

Staff Accounting Schedules

Accompanying the Testimony of Ralph C. Smith

Schedule	Description	Pages
	Revenue Requirement Summary Schedules	
A	Calculation of Revenue Deficiency (Sufficiency)	1
A-1	Gross Revenue Conversion Factor	1
B	Adjusted Rate Base	1
B.1	Summary of Adjustments to Rate Base	1
C	Adjusted Net Operating Income	1
C.1	Summary of Net Operating Income Adjustments	3
D	Capital Structure and Cost Rates	1
	Rate Base Adjustments	
B-1	Remove Construction Work in Progress	1
B-2	Adjust CWIP for Plant in Service by End of Test Year	1
B-3	Plant in Service Addition Subject to Reimbursement	1
B-4	Cash Working Capital - Lead/Lag Study	1
B-5	Accumulated Deferred Income Taxes	1
	Net Operating Income Adjustments	
C-1	Revenue Adjustment for CARES Discount	1
C-2	Remove Depreciation & Property Taxes for CWIP	1
C-3	Depreciation & Property Taxes for CWIP Found to be In-Service in the Test Year	1
C-4	Fleet Fuel Expense	2
C-5	Postage Expense	1
C-6	Normalize Injuries and Damages Expense	1
C-7	Incentive Compensation Expense	1
C-8	Supplemental Executive Retirement Plant (SERP) Expense	1
C-9	Stock Based Compensation Expense	1
C-10	Property Tax Expense	1
C-11	Rate Case Expense	1
C-12	Edison Electric Institute Dues	2
C-13	Other Membership and Industry Association Dues	1
C-14	Interest Synchronization	1
C-15	Depreciation Rates Correction	4
C-15.1	Depreciation Rates Correction - Details of Company's Pre-Correction Calculation	9
C-15.2	Depreciation Rates Correction - Details of Calculation Using Corrected Rates	9
C-16	Emergency Bill Assistance Expense	1
C-17	Markup Above Cost in Charges from Affiliate, Southwest Energy Services	N/A
	Total Pages	53

UNS Electric Inc.
Computation of Increase in Gross Revenue Requirement

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule A

Line No.	Description	Reference	UNS Proposed Original Cost (A)	UNS Proposed Fair Value (B)	Staff Proposed Original Cost (C)	Staff Proposed Fair Value (D)
1	Adjusted Rate Base	Sch. B	$ 140,991,324	$ 177,802,341	$ 130,471,537	$ 167,282,554
2	Rate of Return	Sch. D	9.89%	7.84%	8.99%	7.01%
3	Operating Income Required		$ 13,946,320	$ 13,946,320	$ 11,725,569	$ 11,726,507
4	Net Operating Income Available	Sch. C	$ 8,742,011	$ 8,742,011	$ 9,400,443	$ 9,400,443
5	Operating Income Excess/Deficiency		$ 5,204,309	$ 5,204,309	$ 2,325,126	$ 2,326,064
6	Gross Revenue Conversion Factor	Sch. A-1	1.6346	1.6346	1.634626	1.634626
7	Overall Revenue Requirement		$ 8,507,097	$ 8,507,097	$ 3,800,712	$ 3,802,245

Notes and Source

Cols. A & B taken from UNS Electric, Inc. filing, Schedule A-1

UNS Electric, Inc.
Computation of Gross Revenue Conversion Factor

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule A-1

Line No.	Description	Company Proposed (A)	Staff Proposed (B)
1	Gross Revenue	100.00%	100.00000%
2	Less: Uncollectible Revenue	0.36792%	0.36792%
3	Taxable Income as a Percent	99.63%	99.63208%
4	Less: Federal and State Income Taxes	38.46%	38.46%
5	Change in Net Operating Income	61.18%	61.17609%
6	Gross Revenue Conversion Factor	1.6346	1.634626

Notes and Source

Col.A: UNS Electric Inc. Filing, Schedule C-3
Col.B:

Components of Revenue Requirement Increase

	Amount	Percent
Net Income	$ 2,325,127	61.18%
Federal and State Income Taxes	$ 1,461,601	38.46%
Uncollectibles	$ 13,984	0.37%
Total Revenue Increase	$ 3,800,712	100.00%

UNS Electric, Inc.
Original Cost and RCND Adjusted Rate Base

Test Year Ended June 30, 2006

Line No.	Description	Original Cost As Adjusted by UNS (A)	Original Cost Staff Adjustments (B)	Original Cost As Adjusted by Staff (C)	RCND As Adjusted by UNS (D)	RCND Staff Adjustments (E)	RCND As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 390,513,651	$ (10,555,773)	$ 379,957,878	$ 612,326,062	$ (10,555,773)	$ 601,770,289
2	Less: Accumulated Depreciation	$ (159,524,693)	$ -	$ (159,524,693)	$ (257,585,628)	$ -	$ (257,585,628)
3	Net Utility Plant in Service	$ 230,988,958	$ (10,555,773)	$ 220,433,185	$ 354,740,434	$ (10,555,773)	$ 344,184,661
4	Citizens Acquisition Discount	$ (93,273,341)	$ -	$ (93,273,341)	$ (150,061,415)	$ -	$ (150,061,415)
5	Less: Accum. Amort. - Citizens Acq. Discount	$ (11,224,066)	$ -	$ (11,224,066)	$ (18,123,969)	$ -	$ (18,123,969)
6	Net Citizens Acquisition Discount	$ (82,049,275)	$ -	$ (82,049,275)	$ (131,937,446)	$ -	$ (131,937,446)
7	Total Net Utility Plant	$ 148,939,683	$ (10,555,773)	$ 138,383,910	$ 222,802,988	$ (10,555,773)	$ 212,247,215
8	Customer Advances for Construction	$ (8,692,444)	$ -	$ (8,692,444)	$ (9,559,141)	$ -	$ (9,559,141)
							$ -
9	Customer Deposits	$ (3,778,419)	$ -	$ (3,778,419)	$ (3,778,419)	$ -	$ (3,778,419)
							$ -
10	Accumulated Deferred Income Taxes	$ 1,154,833	$ (161,555)	$ 993,278	$ 1,780,258	$ (161,555)	$ 1,618,703
11	Total Deductions	$ (11,316,030)	$ (161,555)	$ (11,477,585)	$ (11,557,302)	$ (161,555)	$ (11,718,857)
12	Allowance for Working Capital	$ 3,367,671	$ 197,541	$ 3,565,212	$ 3,367,671	$ 197,541	$ 3,565,212
							$ -
13	Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -
							$ -
14	Regulatory Liabilities	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Rate Base	$ 140,991,324	$ (10,519,787)	$ 130,471,537	$ 214,613,357	$ (10,519,787)	$ 204,093,570

Notes and Source

Cols. A and D: UNS Electric Inc. filing, Schedule B

Fair Value Calculation (Per Company)		
Original Cost	$ 140,991,324	
RCND	$ 214,613,357	
Total	$ 355,604,681	
Average (Fair Value)	$ 177,802,341	See Sch. A

Fair Value Calculation (Per Staff)		
Original Cost	$ 130,471,537	
RCND	$ 204,093,570	
Total	$ 334,565,107	
Average (Fair Value)	$ 167,282,554	See Sch. A

UNS Electric, Inc.
Summary of Rate Base Adjustments

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B.1
Page 1 of 1

Line No.	Description	Staff Adjustments	CWIP B-1	Rhode Homes Line Extensions B-2	Customer Advances for Construction B-3	Cash Working Capital B-4	ADIT B-5	N/A B-6
1	Gross Utility Plant in Service	$ (10,555,773)	$ (10,761,154)	$ 442,255	$ (236,874)			
2	Less: Accumulated Depreciation	$ -						
3	Net Utility Plant in Service	$ (10,555,773)	$ (10,761,154)	$ 442,255	$ (236,874)	$ -	$ -	$ -
4	Citizens Acquisition Discount	$ -						
5	Less: Accum. Amort. - Citizens Acq. Discount	$ -						
6	Net Citizens Acquisition Discount	$ -						
7	Total Net Utility Plant	$ (10,555,773)	$ (10,761,154)	$ 442,255	$ (236,874)	$ -	$ -	$ -
8	Customer Advances for Construction	$ -		$ -				
9	Customer Deposits	$ -						
10	Accumulated Deferred Income Taxes	$ (161,555)					$ (161,555)	
11	Total Deductions	$ (161,555)	$ -	$ -	$ -	$ -	$ (161,555)	$ -
12	Allowance for Working Capital	$ 197,541				$ 197,541		
13	Regulatory Assets	$ -						
14	Regulatory Liabilities	$ -						
15	Total Rate Base	$ (10,519,787)	$ (10,761,154)	$ 442,255	$ (236,874)	$ 197,541	$ (161,555)	$ -

UNS Electric, Inc.
Adjusted Net Operating Income

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C

Line No.	Description	As Adjusted by UNS (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Electric Retail Revenues	$ 156,651,860	$ 52,937	$ 156,704,797
2	Sales for Resale	$ 246,016	$ -	$ 246,016
3	Other Operating Revenues	$ 1,589,014	$ -	$ 1,589,014
4	Total Operating Revenues	$ 158,486,890	$ 52,937	$ 158,539,827
	Operating Expenses			
5	Purchased Power	$ 106,224,185	$ -	$ 106,224,185
6	Other O&M Expenses	$ 26,423,248	$ (527,396)	$ 25,895,852
7	Depreciation & Amortization	$ 11,812,574	$ (494,656)	$ 11,317,918
8	Taxes Other Than Income Taxes	$ 3,447,533	$ (292,679)	$ 3,154,854
9	Income Taxes	$ 1,837,339	$ 709,236	$ 2,546,575
10	Total Operating Expenses	$ 149,744,879	$ (605,495)	$ 149,139,384
11	Net Operating Income	$ 8,742,011	$ 658,432	$ 9,400,443

Notes and Source

Col. A: UNS Electric, Inc. filing, Schedule C-1
Col. B: Staff Schedule C.1

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Line No.	Description	Stafff Adjustments	CARES Discount	Remove Depreciation & Property Taxes for CWIP	Depreciation & Property Taxes for CWIP Found in Service	Fleet Fuel Expense	Postage Expense
			C-1	C-2	C-3	C-4	C-5
	Operating Revenues						
1	Electric Retail Revenues	$ 52,937	$ 52,937				
2	Sales for Resale	$ -					
3	Other Operating Revenues	$ -					
4	Total Operating Revenues	$ 52,937	$ 52,937	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Purchased Power	$ -					
6	Other O&M Expenses	$ (527,396)				$ (70,391)	$ 17,503
7	Depreciation & Amortization	$ (494,656)		$ (449,816)	$ 18,265		
8	Taxes Other Than Income Taxes	$ (292,679)		$ (239,696)	$ 8,317		
9	PRE-TAX OPERATING EXPENSES	$ (1,314,731)	$ -	$ (689,512)	$ 26,582	$ (70,391)	$ 17,503
10	PRE-TAX OPERATING INCOME	$ 1,367,668	$ 52,937	$ 689,512	$ (26,582)	$ 70,391	$ (17,503)
11	Income Taxes	$ 709,236	$ 20,433	$ 266,138	$ (10,260)	$ 27,170	$ (6,756)
12	TOTAL OPERATING EXPENSES	$ (605,495)	$ 20,433	$ (423,374)	$ 16,322	$ (43,221)	$ 10,747
13	OPERATING INCOME	$ 658,432	$ 32,504	$ 423,374	$ (16,322)	$ 43,221	$ (10,747)

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Line No.	Description	Injuries and Damages Expense	Incentive Compensation Expense	SERP Expense	Stock Based Compensation Expense	Property Tax Expense	Rate Case Expense
		C-6	C-7	C-8	C-9	C-10	C-11
	Operating Revenues						
1	Electric Retail Revenues						
2	Sales for Resale						
3	Other Operating Revenues						
4	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Purchased Power						
6	Other O&M Expenses	$ (159,063)	$ (42,448)	$ (83,506)	$ (82,873)		$ (111,667)
7	Depreciation & Amortization						
8	Taxes Other Than Income Taxes		$ (1,553)			$ (59,747)	
9	PRE-TAX OPERATING EXPENSES	$ (159,063)	$ (44,001)	$ (83,506)	$ (82,873)	$ (59,747)	$ (111,667)
10	PRE-TAX OPERATING INCOME	$ 159,063	$ 44,001	$ 83,506	$ 82,873	$ 59,747	$ 111,667
11	Income Taxes	$ 61,395	$ 16,984	$ 32,232	$ 31,987	$ 23,061	$ 43,101
12	TOTAL OPERATING EXPENSES	$ (97,668)	$ (27,017)	$ (51,274)	$ (50,886)	$ (36,686)	$ (68,566)
13	OPERATING INCOME	$ 97,668	$ 27,017	$ 51,274	$ 50,886	$ 36,686	$ 68,566

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Line No.	Description	Edison Electric Institute Dues	Other Membership Dues	Interest Synchro-nization	Depreciation Rates Correction	Emergency Bill Assistance	SES Markup Above Cost
		C-12	C-13	C-14	C-15	C-16	C-17
	Operating Revenues						
1	Electric Retail Revenues						
2	Sales for Resale						
3	Other Operating Revenues						
4	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Purchased Power						
6	Other O&M Expenses	$ (8,470)	$ (6,482)			$ 20,000	
7	Depreciation & Amortization				$ (63,105)		
8	Taxes Other Than Income Taxes						
9	PRE-TAX OPERATING EXPENSES	$ (8,470)	$ (6,482)	$ -	$ (63,105)	$ 20,000	$ -
10	PRE-TAX OPERATING INCOME	$ 8,470	$ 6,482	$ -	$ 63,105	$ (20,000)	$ -
11	Income Taxes	$ 3,269	$ 2,502	$ 181,343	$ 24,357	$ (7,720)	$ -
12	TOTAL OPERATING EXPENSES	$ (5,201)	$ (3,980)	$ 181,343	$ (38,748)	$ 12,280	$ -
13	OPERATING INCOME	$ 5,201	$ 3,980	$ (181,343)	$ 38,748	$ (12,280)	$ -

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

UNS Electric, Inc.
Capital Structure & Cost Rates

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule D

Line No.	Capital Source	Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
	UNS - Proposed				
1	Short-Term Debt	$ 5,000	3.97%	6.36%	0.25%
2	Long-Term Debt	$ 59,486	47.18%	8.22%	3.88%
3	Common Stock Equity	$ 61,587	48.85%	11.79%	5.76%
4	Total Capital	$ 126,073	100.00%		9.89%
	ACC Staff - Proposed				
5	Short-Term Debt	$ 5,000	3.96%	6.36%	0.25%
6	Long-Term Debt	$ 59,545	47.21%	8.16%	3.85%
7	Common Stock Equity	$ 61,587	48.83%	10.000%	4.88%
8	Total Capital	$ 126,132	100.00%		8.99%
9	Difference				-0.90%
10	Weighted Cost of Debt				4.10%
	ACC Staff - Proposed Cost of Capital for Fair Value Rate Base				
11	Short-Term Debt	$ 5,172,024	3.09%	6.36%	0.20%
12	Long-Term Debt	$ 61,593,629	36.82%	8.16%	3.00%
13	Common Stock Equity	$ 63,705,884	38.08%	10.000%	3.81%
	Capital financing OCRB	$ 130,471,538			
14	Appreciation above OCRB not recognized on utility's books	$ 36,811,017	22.01%	0% [a]	0.00%
15	Total capital supporting FVRB	$ 167,282,555	100.00%		7.0100%

Notes and Source

Lines 1-4 taken from UNS Electric Inc. filing, Schedule D-1
Lines 5-8: Staff witness David Parcell
Lines 11-15, Col.A:

Fair Value Rate Base	$ 167,282,554	Schedule A
Original Cost Rate Base	$ 130,471,537	Schedule A
Difference	$ 36,811,017	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

UNS Electric, Inc.
Remove Construction Work in Progress

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B-1

Line No.	Description	Amount	Reference
1	Remove Construction Work in Progress	$ (10,761,154)	A & B

Notes and Source

A: UNS Electric Filing, Schedule B-2, page 2, line 1
B: Testimony of Staff witness Ralph Smith

UNS Electric, Inc.
Adjust CWIP for Plant in Service by End of Test Year

Test Year Ended June 30, 2006

Line No.	Description	Plant Account	Amount	Reference
1	Adjustment to Plant in Service for Rhode Homes Line Extensions	365	$ 442,255	A
2	Adjustment to Customer Advances for Construction			A
3	Net Rate Base Adjustment		$ 442,255	

Notes and Source

A: Staff memorandum concerning its Preliminary Field Assessment of Used and Useful Review for UNS Electric as it relates to the Rhode Homes overhead line extensions

Line 2: Letter of Agreement dated March 2, 2006 indicates the customer will pay to the Company a total Customer Advance of $360,117
The Company's response to data request STF 15.4(f) and (g) indicate that, as of June 30, 2006, UNS Electric had received Customer Advances totaling $360,117 for this project, and no additional Customer Advances for this project have been received subsequent to June 30, 2006.

UNS Electric, Inc.
Plant in Service Addition Subject to Reimbursement

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Adjustment to Contributions in Aid of Construction Decrease to Plant in Service	$ (236,874)	Note A

Notes and Source

A: Staff memorandum concerning its Preliminary Field Assessment of Used and Useful Review for UNS Electric as it relates to the Tubac Golf Resort Overhead to Underground Conversion

The Company's response to STF 15.4(d) states that: "this customer requested work was paid 100% by the customer as a Contribution in Aid of Construction."

UNS Electric, Inc.
Cash Working Capital - Lead/Lag Study
For the Test Year Ending 6/30/06

Line No.	Description	FERC	Per UNS Electric Pro Forma Test Year Amount		Staff Adjustments	Staff Adjusted	Expense Lag Days		Net Lag Days (RevLag - Col. D)	Lead/Lag Factor (Col. E/365)	Cash Working Capital Required (Col. F X Col.C)
	(A)		(A)		(B)	(C)	(D)		(E)	(F)	(G)
	Operating Expenses:										
	Non-Cash Expenses -										
1	Bad Debts Expense	904	$ 579,538	1a	-	579,538					$ -
2	Depreciation	403/404	15,594,232	1.2a	(494,656)	15,099,576					-
3	Amortization	406	(3,781,658)	1.2b	-	(3,781,658)					-
4	Deferred Income Taxes		494,521	1.3a		494,521					-
	Other Operating Expenses -										
5	Salaries and Wages (UNSG Direct Employees)	Multi	4,571,466	2.2a		4,571,466	23.33	D.	12.26	0.0336	153,601
6	Incentive Pay (UNSE Direct Employees)	Multi	98,247	3a	(17,962)	80,285	267.00	D.	(231.41)	(0.6340)	(50,901)
7	Purchased Power		106,021,950	1b		106,021,950	33.79	E.	1.80	0.0049	519,508
8	Transmission Other		7,009,878	1c		7,009,878	40.67	F.	(5.08)	(0.0139)	(97,437)
9	Meter Reading		730,556	1d		730,556	33.67	G.	1.92	0.0053	3,872
10	Customer Records & Collection Expenses (excluding alloc.)	903	2,982,604	1e-4b	-	2,982,604	34.94	H.	0.65	0.0018	5,369
11	Office Supplies and Expenses	921	535,854	1.1a		535,854	50.89	I.	(15.30)	(0.0419)	(22,452)
12	Injuries and Damages	925	512,417	1.1b	(159,063)	353,354	70.52	J.	(34.93)	(0.0957)	(33,816)
13	Pension & Benefits	926	1,172,133	1.1c	-	1,172,133	51.37	K	(15.78)	(0.0432)	(50,636)
14	Support Services (Direct Labor, Burdens, System Allocation)		5,631,155	4a	(190,865)	5,440,290	44.77	L.	(9.18)	(0.0252)	(137,095)
15	Property Taxes	408	3,096,371	1.3b	(291,126)	2,805,245	213.00	M.	(177.41)	(0.4861)	(1,363,630)
16	Payroll Taxes	408	348,088	1.3c	(1,553)	346,535	19.87	M.	15.72	0.0431	14,936
17	Current Income Taxes		1,342,818	1.3d		3,513,655	41.42	M.	(5.83)	(0.0160)	(56,218)
18	Interest on Customer Deposits	431	217,492	1.3e		217,492	182.50	Q.	(146.91)	(0.4025)	(87,541)
19	Other Operations and Maintenance	Multi	2,587,216	X	(179,506)	2,407,710	41.21	N.	(5.62)	(0.0154)	(37,079)
20	Total Operating Expenses		149,744,878		(1,334,731)	150,580,984					
	Other Cash Working Capital Elements:										
21	Interest on Long-Term Debt		5,819,157	8a	(469,824)	5,349,333	90.22	O.	(54.63)	(0.1497)	(800,795)
22	Revenue Taxes and Assessments	Calc	$ 13,983,561	P.	343,456	14,327,017	45.71	M.	(10.12)	(0.0277)	(396,858)
23	Total Cash Working Capital - Calculated										$ (2,437,172)
24	Total Cash Working Capital - Per UNS Gas Filing, Schedule B-5, page 3 of 3										(2,634,713)
25	Adjustment to Cash Working Capital										197,541

Notes and Source

UNS Electric filing, Schedule B-5, page 3 of 3
RUCO 1.10 2005 UNSG Lead-Lag Summary.xls
Revenue Lag, in days 35.59
Col.B: Staff workpapers for CWC calculation

Line 17, Col.C, Current income taxes:

26	Per UNS Electric, Current Income Taxes	$ 1,342,818	Col.A, line 14	
27	Staff adjustments to Current Income Taxes	$ 709,236	Schedule C.1	
28	Staff adjusted Current Income Taxes before Revenue Increase	$ 2,052,054	Schedule C	
29	Income taxes for revenue increase	$ 1,461,601	Schedule A-1	
30	Total current income taxes for CWC calculation	$ 3,513,655		

2,546,575	-	$ 2,052,054	=	$ 494,521	
Total Income Taxes		Current Inc Taxes		Deferred Inc Taxes	
Schedule C		Line 28		Col. A, Line 4	

Line 22, Revenue Based Taxes

31	Revenue adjustments	$ 52,937	Schedule C
32	Staff recommended rate increase	$ 3,800,712	Schedule A, filtered through CWC macro
33	Revenue adjustments	$ 3,853,649	
34	Revenue based taxes	0.0891249	B-4 W/P 2
35	Adjustment to revenue based taxes	$ 343,456	

UNS Electric, Inc.
Accumulated Deferred Income Taxes

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B-5

Line No.	Description	Account	Amount	Reference
1	SERP	190	$ (97,217)	A
2	Stock Based Compensation	190	$ (64,338)	A
3	Total Adjustment to ADIT		$ (161,555)	

Notes and Source

A: Staff has removed SERP and Restricted Stock from operating expenses and allocated incentive compensation expense 50/50 to shareholders and ratepayers. This adjustment coordinates the corresponding ADIT amounts with those recommendations.

	Account and Description	Per Books (1)	UNS Electric Adjustment (2)	UNS Electric Adjusted		Staff Adjustment
	Account 190					
4	SERP	$ 99,736	$ (2,519)	$ 97,217	a	$ (97,217)
5	Restricted Stock	$ 28,728	$ (1,970)	$ 26,758	b	$ (26,758)
6	Dividend Equivalents	$ 37,661	$ (1,844)	$ 35,817	c	$ (35,817)
7	Stock Options	$ -	$ 1,763	$ 1,763	d	$ (1,763)
8	Stock Based Compensation related ADIT	$ 66,389	$ (2,051)	$ 64,338		$ (64,338)

(1) Response to STF 3.60
(2) UNS Electric ADIT workpapers
a: UNS Electric workpaper "Pro Forma ADIT - Account 190" "SERP 12G"
b: UNS Electric workpaper "Pro Forma ADIT - Account 190" "Restricted Stock 12F"
c: UNS Electric workpaper "Pro Forma ADIT - Account 190" "Dividend Equivalents 12C"
d: UNS Electric workpaper "Pro Forma ADIT - Account 190" "Stock Options 12H"

UNS Electric, Inc.
Revenue Adjustment for CARES Discount

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Remove Company Revenue Adjustment for Company's Proposed Revisions to CARES Discounts	$ 52,937	A&B

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 1, line 1
B: Testimony of Staff witness Julie McNeely-Kirwan

UNS Electric, Inc.
Remove Depreciation & Property Taxes for CWIP

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-2

Line No.	Description	Account	Amount	Reference
1	CWIP Related Depreciation Expense	403	$ (449,816)	A
2	CWIP Related Property Tax Expense	408	$ (239,696)	A
3	Total Adjustments		$ (689,512)	

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 4, lines 7 and 8

UNS Electric, Inc.
Depreciation & Property Taxes for CWIP Found to be In-Service in the Test Year

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-3

Line No.	Description	Account	Amount	Reference
1	Rhode Homes Related Depreciation Expense	403	$ 18,265	A
2	Rhode Homes Related Property Tax Expense	408	$ 8,317	B
3	Total Adjustments		$ 26,582	

A: Depreciation Rate taken from Attachment REW-2, Statement A, from Dr. White's testimony

		Plant Account	Amount	Depreciation Rate	Depreciation Expense
4	Rhode Homes Overhead Line Extensions (see Sch. B-2)	365	$ 442,255	4.13%	$ 18,265

B: **Calculation of Property Tax Expense**

5	Rhode Homes Overhead Line Extensions	$ 442,255	
6	Less: Accumulated Depreciation	$ (18,265)	
7	Subtotal	$ 423,990	
8	Assessment Ratio	23.5%	
9	Taxable Value	$ 99,638	
10	Mohave Property Tax Rate	8.3471%	per Company's Property Tax adjustment workpaper
11	Property Tax Expense	$ 8,317	

UNS Electric, Inc.
Fleet Fuel Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-4

Line No.	Description	Amount	Reference
1	UNS Electric Adjustment to Fleet Fuel Expense	$ 73,661	A
2	Staff Recommended Pro Forma Adjustment to Fleet Fuel Expense	$ 3,270	B
3	Adjustment to Fleet Fuel Expense	$ (70,391)	L2 - L1

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 3, lines 5 and 6

B: Per Company's workpapers showing calculation of Fleet Fuel Expense adjustment (except where noted)

4	Average construction FTE from July 2005 to June 2006	109.2	
5	Average miles driven/contruction FTE (Total miles = 1,560,271)	14,293	
6	Construction FTE for July 2006	114.5	
7	Assumed 2006-2007 mileage	1,636,549	L5 x L6
8	Miles/gallon (1,560,271 / 204,180)	7.63	
9	Gallons purchased	214,504	L7 / L8
10	Weighted average price per gallon	$ 2.69	Note C
11	Pro forma fuel expenditures	$ 577,016	L.9 x L.10
12	Test year expenditures	$ 573,746	
13	Staff Recommended pro forma adjustment to Fleet Fuel Expense	$ 3,270	L11 - L12

C: **Amounts taken from the Company's response to STF 11.24**

		Gallons	Fuel Cost	Weighted Average Cost/Gal
14	Wright Express (September 2006 - May 2007)	51,891	$ 139,467	$ 2.69
15	Kingman Gascard (September 2006 - May 2007)	71,885	$ 192,615	$ 2.68
16	Parker Oil (February through May 2007)	7,775	$ 22,304	$ 2.87
17	Weighted Average	131,551	$ 354,386	$ 2.69

UNS Electric, Inc.
Adjustment to Fleet Fuel Expense (supplemental worksheet)
Allocation of Staff adjustment to FERC accounts

Docket No. E-04204A-06-0783
Schedule C-4

Test Year Ended June 30, 2006

Co	Acct	Expense Type	FERC Account	DR	CR	Net Amount	% of Total	O&M Adjustment	Staff Adjustment
33	55000	403	546	$7,634.11		$7,634.11	0.85%	$28	($600)
33	55000	403	548	$1,198.26		$1,198.26	0.13%	$4	($94)
33	55000	403	549	$188.36		$188.36	0.02%	$1	($15)
33	55000	403	551	$9,428.90		$9,428.90	1.05%	$34	($741)
33	55000	403	553	$17,592.83		$17,592.83	1.96%	$64	($1,383)
33	55000	403	554	$9,332.50		$9,332.50	1.04%	$34	($734)
33	55000	403	557	$2,550.60		$2,550.60	0.28%	$9	($200)
33	55000	403	562	$3,237.60		$3,237.60	0.36%	$12	($255)
33	55000	403	563	$472.61		$472.61	0.05%	$2	($37)
33	55000	403	566	$2,075.77		$2,075.77	0.23%	$8	($163)
33	55000	403	570	$7,633.80		$7,633.80	0.85%	$28	($600)
33	55000	403	571	$395.23		$395.23	0.04%	$1	($31)
33	55000	403	580	$8,414.78		$8,414.78	0.94%	$31	($661)
33	55000	403	581	$54,108.09		$54,108.09	6.04%	$198	($4,253)
33	55000	403	582	$4,099.30		$4,099.30	0.46%	$15	($322)
33	55000	403	583	$33,150.21		$33,150.21	3.70%	$121	($2,606)
33	55000	403	584	$65,053.92		$65,053.92	7.26%	$238	($5,114)
33	55000	403	585	$165.43		$165.43	0.02%	$1	($13)
33	55000	403	586	$98,161.79		$98,161.79	10.96%	$358	($7,716)
33	55000	403	587	$1,717.22		$1,717.22	0.19%	$6	($135)
33	55000	403	588	$43,342.83		$43,342.83	4.84%	$158	($3,407)
33	55000	403	590	$9,421.61		$9,421.61	1.05%	$34	($741)
33	55000	403	592	$53,782.89		$53,782.89	6.01%	$196	($4,228)
33	55000	403	593	$93,650.75		$93,650.75	10.46%	$342	($7,362)
33	55000	403	594	$18,195.04		$18,195.04	2.03%	$66	($1,430)
33	55000	403	595	$8,141.32		$8,141.32	0.91%	$30	($640)
33	55000	403	596	$8,089.99		$8,089.99	0.90%	$30	($636)
33	55000	403	598	$171.22		$171.22	0.02%	$1	($13)
33	55000	403	901	$24,434.41		$24,434.41	2.73%	$89	($1,921)
33	55000	403	902	$13,012.92		$13,012.92	1.45%	$48	($1,023)
33	55000	403	903	$132,933.49		$132,933.49	14.85%	$485	($10,450)
33	55000	403	905	$1,969.74		$1,969.74	0.22%	$7	($155)
33	55000	403	908	$7,737.47		$7,737.47	0.86%	$28	($608)
33	55000	403	909	$7,376.08		$7,376.08	0.82%	$27	($580)
33	55000	403	910	$181.63		$181.63	0.02%	$1	($14)
33	55000	403	920	$0.00		$0.00	0.00%	$0	$0
33	55000	403	921	$111,418.51		$111,418.51	12.44%	$407	($8,758)
33	55000	403	925	$165.65		$165.65	0.02%	$1	($13)
33	55000	403	930	$34,835.19		$34,835.19	3.89%	$127	($2,739)
				$895,472.05	$0.00	$895,472.05		$3,270	($70,391)

Staff adjustment amount from page 1: $3,270 $ (70,391)

UNS Electric, Inc.
Postage Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-5

Line No.	Description	Amount	Reference
1	UNS Electric Annualized Postage Expense	$ 341,321	A
2	Recommended Staff Annualized Postage Expense	$ 358,824	B
3	Adjustment to Annualized Postage Expense	$ 17,503	L2 - L1

Notes and Source

A: Per Company workpaper used in calculating its Postage Expense adjustment

B:

4	UNS Electric Annualized Postage Expense	$ 341,321
5	Postage increase effective 5/14/07 (.41/.39)	1.05
6	Staff adjusted annualized Postage Expense	$ 358,824

UNS Electric, Inc.
Normalize Injuries and Damages Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-6

Line No.	Description	Amount	Reference
1	UNS Electric Test Year Injuries and Damages Expense	$ 562,403	A
2	Staff Recommended Normalized Injuries and Damages Expense	$ 403,340	B
3	Adjustment to Injuries and Damages Expense	$ (159,063)	L2 - L1

Notes and Source

A: Amount taken from UNS Electric's response to STF 3.101

B: Amounts taken from UNS Electric's response to STF 3.101

January through December 2004	$ 352,589
January through December 2005	$ 356,992
January through December 2006	$ 500,440
Total	$ 1,210,021
Normalized over three years	3
Staff Recommended Normalized Injuries and Damages Expense	$ 403,340

FERC Account 925

UNS Electric, Inc.
Incentive Compensation Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-7

Line No.	Description	Amount	Reference
1	Staff Adjustment to UES's Performance Enhancement Plan (PEP)	$ (17,962)	A
2	Staff Adjustment to UES's Other Incentive Comp	$ (24,486)	B
3	Total Adjustment to Incentive Compensation Expense	$ (42,448)	
4	Adjustment to Taxes Other Than Income	$ (1,553)	B

Notes and Source

A: Per Company's workpapers showing calculation of Incentive Compensation adjustment (except where noted)

FERC Acct	FERC Account Description	Company Amount	Disallowance Percentage	Staff Adjusted Amount
	Performance Enhancement Plan			
581	Distribution - Load Dispatching	$ 292	50%	$ 146
588	Distribution - Miscellaneous Expense	$ 3,428	50%	$ 1,714
593	Distribution - Maintenance of Overhead Lines	$ 3,612	50%	$ 1,806
901	Customer Accounting - Supervision	$ 5,374	50%	$ 2,687
903	Customer Records & Collection Expense	$ 585	50%	$ 293
909	Informational & Instructional Advertising Expense	$ 2,139	50%	$ 1,070
920	A&G Salaries	$ 20,491	50%	$ 10,246
		$ 35,921		$ 17,962
408	Taxes Other Than Income	$ 3,105	50%	$ 1,553
B: Per UNS Electric Inc.'s response to STF 3.83				
920	Deferred Compensation Plan	$ 9,035	50%	$ 4,518
923	Officer's Long Term Incentive Plan	$ 39,935	50%	$ 19,968
		$ 48,970		$ 24,486

UNS Electric, Inc.
Supplemental Executive Retirement Plant (SERP) Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-8

Line No.	Description	Amount	Reference
1	Remove Supplemental Executive Retirement Plan Expense	$ (83,506)	A

Notes and Source

A: Per the Company's response to STF 3.83

FERC 923

UNS Electric, Inc.
Stock Based Compensation Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-9

Line No.	Description	Amount	Reference
1	Remove Stock Based Compensation Expense	$ (82,873)	Note A

Notes and Source

A: Per Company's response to STF 10.11

Stock Option Expense	$	62,904
Performance Share Expense	$	19,969
Total	$	82,873

UNS Electric, Inc.
Property Tax Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-10
Page 1 of 1

Line No.	Description	Amount	Reference
1	UNS Electric Proposed Decrease to Property Tax Expense	$ (130,301)	A
2	*Staff Proposed Decrease to Property Tax Expense*	$ (190,048)	B
3	Adjustment to Property Tax Expense	$ (59,747)	L2 - L1

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 5, line 8

B: Amounts taken from Company workpapers used to calculate its property tax expense adjustment

	Utility Plant in Service Taxes	Generation	Transmission	Distribution	General/ Intangible	Total
4	Total Net Plant in Service - Rate Base	$ 18,471,624	$ 15,073,774	$ 99,401,194	$ 16,474,253	$ 149,420,845
5	Less: Non-Taxable Licensed Transportation in Rate Base	$ -	$ -	$ -	$ (3,834,788)	$ (3,834,788)
6	Less: Land Cost & Rights of Way in Rate Base	$ (408,603)	$ (681,822)	$ (695,700)	$ (30,719)	$ (1,816,844)
7	Less: Environmental Property in Rate Base	$ -	$ -	$ (5,563,286)		$ (5,563,286)
8	Less: Non-Taxable WAPA Portion of N Havasu Sub			$ (4,674,822)		$ (4,674,822)
9	Less: CWIP in Rate Base	$ (777,167)	$ (1,234,041)	$ (7,840,042)	$ (951,066)	$ (10,802,316)
10	Less: Net Book Value of Generation	$ (17,285,854)				$ (17,285,854)
11	Plus: Full Cash Value of Generation	$ 7,943,440				$ 7,943,440
12	Plus: Land FCV per AZ Department of Revenue			$ 1,551,539		$ 1,551,539
13	Plus: Materials and Supplies in Rate Base			$ 5,650,559		$ 5,650,559
14	Plant in Service Full Cash Value	$ 7,943,440	$ 13,157,911	$ 87,829,442	$ 11,657,680	$ 120,588,473
15	Assessment Ratio	23.5%	23.5%	23.5%	23.5%	
16	Taxable Value	$ 1,866,708	$ 3,092,109	$ 20,639,919	$ 2,739,555	$ 28,338,291
17	Average Tax Rate	9.6858%	9.6858%	9.6858%	9.6858%	
18	Property Tax - Subtotal	$ 180,806	$ 299,495	$ 1,999,141	$ 265,348	$ 2,744,790
19	Environmental Property in Rate Base	$ -	$ -	$ 5,563,286	$ -	
20	Statutory Full Cash Value Adjustment	50%	50%	50%	50%	
21	Environmental Full Cash Value	$ -	$ -	$ 2,781,643	$ -	
22	Assessment Ratio	23.5%	23.5%	23.5%	23.5%	
23	Taxable Value	$ -	$ -	$ 653,686	$ -	
24	Average Tax Rate	9.6858%	9.6858%	9.6858%	9.6858%	
25	Property Tax - Subtotal	$ -	$ -	$ 63,315	$ -	$ 63,315
26	Total Property Taxes	$ 180,806	$ 299,495	$ 2,062,456	$ 265,348	$ 2,808,105
27	Less: Recorded Property Taxes Excluding Call Center	$ (101,364)	$ (395,121)	$ (2,266,077)	$ (222,391)	$ (2,984,953)
28	Property Tax Expense Adjustment (subtotal)	$ 79,442	$ (95,626)	$ (203,621)	$ 42,957	$ (176,848)
29	Less: Estimated Property Tax Related to PHFFU					$ (13,200) *
30	Property Tax Expense Adjustment					$ (190,048)

***Plant Held for Future Use**

	Transmission	*Distribution*	Total
Original Cost	$ 320,000	$ 120,000	$ 440,000
Estimated Property Tax Rate	3.0%	3.0%	
Estimated Property Tax Expense	$ 9,600	$ 3,600	$ 13,200

2008 Arizona Statutory Assessment Ratio 23.5%

FERC Account 408

UNS Electric, Inc.
Rate Case Expense

Docket No. E-04204A-06-0783
Schedule C-11

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	UNS Electric Rate Case Expense per Company Filing	$ 200,000	A
2	Staff Recommended Rate Case Expense	$ 88,333	B
3	Adjustment to Rate Case Expense	$ (111,667)	L2 - L1

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 3, line 6

B:	Staff Recommended Rate Case Expense	$ 265,000	Note 1
	Normalized Over Three Years	3	
	Staff Recommended Normalized Rate Case Expense	$ 88,333	

(1) Reflects an escalation of approximately 4% over the allowance recommended by Staff in the recent UNS Gas rate case

UNS Electric, Inc.
Edison Electric Institute Dues

Docket No. E-04204A-06-0783
Schedule C-12

Test Year Ended June 30, 2006

Line No.	Description	Test Year Amount (A)	Company Adjustment (B)	Company Adjusted Amount (C)	Staff Adjustment (D)	Staff Adjusted (E)
1	Regular Dues	$ 10,000	$ (2,000)	$ 8,000	$ (2,993) a	$ 5,007
2	2005 UARG	$ 24,071	$ -	$ 24,071	$ (2,675) b	$ -
3	2006 UARG	$ 2,802	$ -	$ 2,802	$ (2,802)	$ -
4	Total Test Year EEI Dues	$ 36,873	$ (2,000)	$ 34,873	$ (8,470)	$ 5,007
5	Journal Entry to Correct 2005 UARG per G/L	$ (21,396)	$ -	$ (21,396)	$ -	$ -
6	Adjusted Test Year EEI Dues	$ 15,477	$ (2,000)	$ 13,477	$ (8,470)	$ 5,007

Notes and Source

Col. A: Amounts taken from the Company's response to STF 3.72

a: Staff adjustment for Regular Dues based on a disallowance percentage of 49.93% (see page 2)

	Staff Adjustment
Regular Dues	$ 10,000
Regular Dues disallowance percentage	49.93%
Staff adjustment to Regular Dues	$ 4,993
Less: Company adjustment	$ (2,000)
Remaining Staff adjustment to Regular Dues	$ 2,993

b: Allocation of TEP's portion of 2005 UARG in the amount of $24,071 booked in error. Corrected by Journal Entry 910.

TEP allocation of 2005 UARG	$ 24,071
Correcting JE910	$ (21,396)
UNS Electric allocation of 2005 UARG	$ 2,675

Col D: Per letter from Edison Electric Institute included in Company's workpapers for its EEI adjustment, 100% of environmental related separately funded activities are classified as "non-deductible" expenses

FERC 930

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core Dues Activities
For the Year Ended December 31, 2005

NARUC Operating Expense Category	% of Dues	Recommended Disallowance
Legislative Advocacy	20.38%	20.38%
Legislative Policy Research	6.02%	
Regulatory Advocacy	16.49%	16.49%
Regulatory Policy Research	13.99%	
Advertising	1.67%	1.67%
Marketing	3.68%	3.68%
Utility Operations and Engineering	11.31%	
Finance, Legal, Planning and Customer Service	18.75%	
Public Relations	7.71%	7.71%
Total Expenses	100.00%	49.93%

Comments:

* The above percentages represent expenses associated with EEI's core dues activities, based on the operating expense categories established by NARUC. Core expenses are those expenses paid for by shareholder-owned electric utilities' dues.

* The legislative advocacy percent will differ slightly for IRS reporting requirements. For 2005, the lobbying % for IRS reporting is 19.4%.

* Administrative expenses are included in the percentages listed above. Approximately 11% of EEI's core dues expenses are administrative.

UNS Electric, Inc.
Other Membership and Industry Association Dues

Docket No. E-04204A-06-0783
Schedule C-13

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Arizona Utility Investors Association	$ 2,500	930
2	Alliance of Utility Shareholder Associations (AUSA)	$ 100	930
3	Golden Valley Chamber of Commerce	$ 70	930
4	Kingman Mohave Lions Club	$ 120	921/930
5	Kingman Rotary Club	$ 383	921/930
6	Kingman Route 66 Rotary Club	$ 508	921/930
7	Kingsmen	$ 125	930
8	Kiwanis Club of Havasu	$ 666	930
9	Mohave Museum of History & Arts	$ 200	930
10	Nogales-Santa Cruz Chamber of Commerce	$ 60	930
11	Arizona-Mexico Commission	$ 1,750	930.1
12	Total Membership Dues	$ 6,482	

		Total From Above	Adjustment
13	Total Amount Recorded in Account 921	$ 568	$ (568)
14	Total Amount Recorded in Account 930	$ 5,914	$ (5,914)
15	Total	$ 6,482	$ (6,482)

Notes and Source

Amounts taken from the Company's response to STF 3.72

L.11: Also see responses to data requests STF 3.55 and MM DR 2.27:
"The $1,750 for the Arizona-Mexico Commission should have been removed from expenses included in the revenue requirement. This invoice was overlooked in error and will be adjusted out of test year expense."

UNS Electric, Inc.
Interest Synchronization

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-14

Line No.	Description		Amount	Reference
1	Adjusted rate base	$	130,471,537	Schedule B
2	Weighted cost of debt		4.10%	Schedule D
3	Synchronized interest deduction	$	5,349,333	Line 1 x Line 2
4	Synchronized interest deduction per UNS Electric	$	5,819,157	Note A
5	Difference (decreased) increased interest deduction	$	(469,824)	Line 3 - Line 4
6	Combined federal and state income tax rates		38.598%	UNS Electric Sch. C-3
7	Increase (decrease) to income tax expense	$	181,343	

Notes and Source

A RUCO 1.10 2006 UNSE Lead-Lag Summary.xls
Also, UNS Electric filing, Schedule B-5, page 3 of 3, line 21

UNS Electric, Inc.
Depreciation Rates Correction

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-15

Line No.	Description	Amount	Reference
1	Adjustment to Depreciation & Amortization Expense	$ (63,105)	A

Notes and Source

A: Per Company's workpapers used to calculate its depreciation expense adjustment (except where noted)

FERC	Description	UNS Electric Proforma Adj. to Depreciation Expense	Staff Proforma Adj. to Depreciation Expense	Staff Adjustment	Additional Reference
403	Depreciation Expense	$ 122,500	$ 57,628	$ (64,872)	Pages 2 & 3
404	Amortization of Utility Plant	$ 323,410	$ 323,410	$ -	Page 3
406	Amortization of Utility Plant Acquisition Adjustment	$ 137,076	$ 138,843	$ 1,767	Page 4
	Total	$ 582,986	$ 519,881	$ (63,105)	

UNS Electric, Inc.
Depreciation & Amortization Expense - Supplemental Worksheet

Docket No. E-04204A-06-0783
Schedule C-15

Test Year Ended June 30, 2006

Depreciation Annualization Adjustment

Line No.	FERC Account	Description	Balance at 6/30/06	Adjustments	Adjusted Balance	Depreciation Rate	Annualized Depreciation	
		A. Rates Per Company Proforma Adjustment						
1	392	Transportation Equipment - Class 1	$ 366,331	$ 10,369	$ 376,700	12.75%	$ 48,029	
2	392	Transportation Equipment - Class 2	$ 1,151,599	$ 32,595	$ 1,184,194	16.99%	$ 201,195	
3	392	Transportation Equipment - Class 3	$ 1,185,238	$ 33,548	$ 1,218,786	20.21%	$ 246,317	
4	392	Transportation Equipment - Class 4	$ 5,641,612	$ 159,683	$ 5,801,295	13.47%	$ 781,434	
5	392	Transportation Equipment - Class 5	$ 1,995,626	$ 56,485	$ 2,052,111	12.55%	$ 257,540	
7		Total Annualized Transportation Equip.					$ 1,534,515	
		B. Rates Per Response to STF 11.8						
8	392	Transportation Equipment - Class 1	$ 366,331	$ 10,369	$ 376,700	11.48%	$ 43,245	
9	392	Transportation Equipment - Class 2	$ 1,151,599	$ 32,595	$ 1,184,194	15.29%	$ 181,063	
10	392	Transportation Equipment - Class 3	$ 1,185,238	$ 33,548	$ 1,218,786	18.69%	$ 227,791	
11	392	Transportation Equipment - Class 4	$ 5,641,612	$ 159,683	$ 5,801,295	11.97%	$ 694,415	
12	392	Transportation Equipment - Class 5	$ 1,995,626	$ 56,485	$ 2,052,111	11.29%	$ 231,683	
13		Total Annualized Transportation Equip.					$ 1,378,197	
		C. Staff Adjustment						
14		Staff Adjustment Before Capitalization					$ (156,318)	L13 - L7
15		O&M Portion of Vehicle Depreciation					41.5%	
16		Staff Adjustment to Depreciation Expense					$ (64,872)	L14 x L15

Notes and Source

Staff proforma adjustment for Depreciation & Amortization based on revised depreciation rates for FERC account 392 - Transportation Equipment, which reflected a 10% net salvage rate that was inadvertently omitted from the depreciation study as addressed in the responses to STF 3.39 and STF 11.8

UNS Electric, Inc.
Depreciation & Amortization Expense - Supplemental Worksheet

Docket No. E-04204A-06-0783
Schedule C-15

Test Year Ended June 30, 2006

Depreciation Annualization Adjustment

Line No.	Description	Account 403	Account 404	O&M Exp.	Total
	UNS Electric Proforma Adjustment - Schedule 15.1, page 12				
1	Test Year Recorded	$ 14,308,205	$ 390,304	$ 332,503	$ 15,031,012
2	Annualized Depreciation	$ 16,110,715	$ 713,714		$ 16,824,429
3	Less: Depr on CWIP Removed	$ (449,816)			$ (449,816)
4	Vehicle Depreciation Chgs CWIP	$ (1,534,515)		$ 636,824	$ (897,691)
5	Adjusted Annualized Depreciation	$ 14,126,384	$ 713,714	$ 636,824	$ 15,476,922
6	Adjustment Amount	$ (181,821)	$ 323,410	$ 304,321	$ 445,910

	Staff Proforma Adjustment - Schedule 15.2, page 8	Account 403	Account 404	O&M Exp.	Total	
7	Test Year Recorded	$ 14,308,205	$ 390,304	$ 332,503	$ 15,031,012	
8	Annualized Depreciation	$ 15,954,397	$ 713,714		$ 16,668,111	
9	Less: Depr on CWIP Removed	$ (449,816)			$ (449,816)	
10	Vehicle Depreciation Chgs CWIP	$ (1,378,197)		571,952	$ (806,245)	
11	Adjusted Annualized Depreciation	$ 14,126,384	$ 713,714	$ 571,952	$ 15,412,050	
12	Adjustment Amount	$ (181,821)	$ 323,410	$ 239,449	$ 381,038	
13	Staff Adjustment				$ (64,872)	L12 - L6

UNS Electric, Inc.
Depreciation & Amortization Expense - Supplemental Worksheet

Test Year Ended June 30, 2006

Acquisition Discount Annualization Adjustment

Line No.	FERC Account	Description	Balance at 6/30/06	Adjustments	Adjusted Balance	Depreciation Rate	Annualized Depreciation	
		Rates Per Company Proforma Adjustment						
1	392	Transportation Equipment - Class 1	$ (51,192)	$ 39,563	$ (11,629)	12.75%	$ (1,483)	
2	392	Transportation Equipment - Class 2	$ (16,191)	$ 12,513	$ (3,678)	16.99%	$ (625)	
3	392	Transportation Equipment - Class 3	$ (92,982)	$ 71,860	$ (21,122)	20.21%	$ (4,269)	
4	392	Transportation Equipment - Class 4	$ (362,404)	$ 280,080	$ (82,324)	13.47%	$ (11,089)	
5	392	Transportation Equipment - Class 5	$ -	$ -	$ -	12.55%	$ -	
7		Total Annualized Amort-Acq Adj	$ (522,769)	$ 404,016	$ (118,753)		$ (17,466)	
		Rates Per Response to STF 11.8						
8	392	Transportation Equipment - Class 1	$ (51,192)	$ 39,563	$ (11,629)	11.48%	$ (1,335)	
9	392	Transportation Equipment - Class 2	$ (16,191)	$ 12,513	$ (3,678)	15.29%	$ (562)	
10	392	Transportation Equipment - Class 3	$ (92,982)	$ 71,860	$ (21,122)	18.69%	$ (3,948)	
11	392	Transportation Equipment - Class 4	$ (362,404)	$ 280,080	$ (82,324)	11.97%	$ (9,854)	
12	392	Transportation Equipment - Class 5	$ -	$ -	$ -	11.29%	$ -	
13		Total	$ (522,769)	$ 404,016	$ (118,753)		$ (15,699)	
14		Staff Adjustment					$ 1,767	L13 - L7

Proforma Adjustment to FERC Account 406

		Per Company Adj. Workpaper	Staff Adjusted	Staff Adjustment
15	Intangible Plant	$ (181,550)	$ (181,550)	
16	Other Production Plant	$ (136,670)	$ (136,670)	
17	Transmission Plant	$ (400,629)	$ (400,629)	
18	Distribution Plant	$ (2,824,706)	$ (2,824,706)	
19	General Plant	$ (238,101)	$ (236,334)	
		$ (3,781,656)	$ (3,779,889)	
20	Test Year Amount per Books	$ (3,918,732)	$ (3,918,732)	
21	Adjustment - FERC 406	$ 137,076	$ 138,843	$ 1,767

Notes and Source

Staff proforma adjustment for Acquisition Discount Annualization Adjustment based on revised depreciation rates for FERC account 392 - Transportation Equipment, which reflected a 10% net salvage rate that was inadvertently omitted from the depreciation study as addressed in the responses to STF 3.39 and STF 11.8

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Depreciation Annualization - Detail by FERC
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	November 28, 2006
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
FERC 403 & 404			
303	Miscellaneous Intangible Plant	$320,122	
341	Structures & Improvements	$73	
342	Fuel Holders, Producers, & Accessories	$131	
343	Prime Movers	$1,740	
344	Generators	$132	
345	Accessory Electric Equipment	$317	
346	Misc. Power Plant Equipment	$79	
352	Structures & Improvements	$62	
353	Station Equipment	$4,437	
354	Towers & Fixtures	$182	
355	Poles & Fixtures	$6,279	
356	Overhead Conductors & Devices	$2,661	
359	Roads & Trails	$32	
361	Structures & Improvements	$1,087	
362	Station Equipment	$11,845	
364	Poles, Towers, & Fixtures	$27,668	
365	Overhead Conductors & Devices	$18,396	
366	Underground Conduit	$4,718	
367	Underground Conductors & Devices	$10,668	
368	Line Transformers	$19,806	
369	Services	$3,877	
370	Meters	$2,341	
373	Street Lights and Signal Systems	$1,321	
390	Structures & Improvements	$3,674	
391	Office Furniture & Equipment	$2,504	
392	Transportation Equipment		$351
393	Stores Equipment	$28	
394	Tools, Shop, & Garage Equipment	$616	
395	Laboratory Equipment	$322	
396	Power Operated Equipment	$357	
397	Communication Equipment	$726	
398	Miscellaneous Equipment	$57	
FERC 406			
303	Miscellaneous Intangible Plant		$10,140
341	Structures & Improvements	$72	
342	Fuel Holders, Producers, & Accessories	$255	
343	Prime Movers	$2,947	
344	Generators	$270	
345	Accessory Electric Equipment	$561	
346	Misc. Power Plant Equipment	$160	

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Depreciation Annualization - Detail by FERC
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	November 28, 2006
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
352	Structures & Improvements	$44	
353	Station Equipment	$6,038	
354	Towers & Fixtures	$357	
355	Poles & Fixtures	$6,439	
356	Overhead Conductors & Devices	$3,525	
359	Roads & Trails	$46	
361	Structures & Improvements	$1,748	
362	Station Equipment	$16,268	
364	Poles, Towers, & Fixtures	$33,522	
365	Overhead Conductors & Devices	$20,619	
366	Underground Conduit	$6,754	
367	Underground Conductors & Devices	$10,428	
368	Line Transformers	$18,524	
369	Services	$5,937	
370	Meters	$3,479	
373	Street Lights and Signal Systems	$1,908	
390	Structures & Improvements	$641	
391	Office Furniture & Equipment	$4,538	
393	Stores Equipment	$37	
394	Tools, Shop, & Garage Equipment	$908	
395	Laboratory Equipment	$305	
396	Power Operated Equipment	$201	
397	Communication Equipment	$641	
398	Miscellaneous Equipment	$42	
	ENTRY TOTAL	**$593,473**	**$10,491**

NET ENTRY **$582,981**

(rounding variance of $5 with unallocated amounts is ignored - immaterial)

Reason for Adjustment

To adjust test year recorded depreciation to reflect annualized depreciation based on ending plant balances and the depreciation rates resulting from Dr. White's study. This adjustment excludes the effects of depreciation on the level of CWIP requested for inclusion in rate base.

To adjust test year recorded amortization expense to reflect acquisition discount in Decision No. 66028 and the depreciation rates resulting from Dr. White's study.

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Depreciation Annualization - Summary by FERC
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	November 26, 2006
PREPARED BY:	E. Fowler
CHECKED BY:	C. Dabelstein
REVIEWED BY:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
403	Depreciation Expense	$122,500	
404	Amortization of Utility Plant	$323,410	
406	Amortization of Utility Plant Acquisition Adjustments	$137,076	
	ENTRY TOTAL	**$582,986**	**$0**

Reason for Adjustment

To adjust test year recorded depreciation and amortization expense to reflect the final adjusted balances

UNS Electric, Inc.
Allocation of Depreciation & Amortization Pro Forma Adjustment to FERC Accounts
Test Year Ended June 30, 2006

Function	Plt Acct & Desc	403 %	403 $122,500	403 %	404 $323,410	Total 403 & 404 $445,910	406 %	406 $137,076	Total $582,986
Intangible	302-Franchises & Consents	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Intangible	303-Intangibles	0.00%	$0	98.98%	$320,122	$320,122	-7.40%	($10,140)	$309,983
	Total Intangible		$0		$320,122	$320,122		($10,140)	$309,983
Other Production	340-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Other Production	341-Struct & Imprv	0.06%	$73	0.00%	$0	$73	0.05%	$72	$146
Other Production	342-Fuel Holders and Accessories	0.11%	$131	0.00%	$0	$131	0.19%	$255	$386
Other Production	343-Prime Movers	1.42%	$1,740	0.00%	$0	$1,740	2.15%	$2,947	$4,686
Other Production	344-Generators	0.11%	$132	0.00%	$0	$132	0.20%	$270	$403
Other Production	345-Accessory Elec Eq	0.26%	$317	0.00%	$0	$317	0.41%	$561	$879
Other Production	346-Misc Pwr Plt Eq	0.06%	$79	0.00%	$0	$79	0.12%	$160	$239
	Total Other Production		$2,473		$0	$2,473		$4,266	$6,738
Transmission	350-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Transmission	352-Str & Impr	0.05%	$62	0.00%	$0	$62	0.03%	$44	$106
Transmission	353-Station Eq	3.62%	$4,437	0.00%	$0	$4,437	4.41%	$6,038	$10,475
Transmission	354-Towers & Fixtures	0.15%	$182	0.00%	$0	$182	0.26%	$357	$539
Transmission	355-Poles & Fixtures	5.13%	$6,279	0.00%	$0	$6,279	4.70%	$6,439	$12,718
Transmission	356-OH Conduct & Devices	2.17%	$2,661	0.00%	$0	$2,661	2.57%	$3,525	$6,186
Transmission	358-UG Conductors & Devices	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Transmission	359-Roads & Trails	0.03%	$32	0.00%	$0	$32	0.03%	$46	$78
	Total Transmission		$13,654		$0	$13,654		$16,449	$30,103
Distribution	360-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Distribution	361-Struct & Imprv	0.89%	$1,087	0.00%	$0	$1,087	1.28%	$1,748	$2,835
Distribution	362-Station Eq	9.67%	$11,845	0.00%	$0	$11,845	11.87%	$16,268	$28,113
Distribution	364-Poles, Towers & Fixtures	22.59%	$27,668	0.00%	$0	$27,668	24.46%	$33,522	$61,190
Distribution	365-OH Conduct & Devices	15.02%	$18,396	0.00%	$0	$18,396	15.04%	$20,619	$39,015
Distribution	366-UG Conduit	3.85%	$4,718	0.00%	$0	$4,718	4.93%	$6,754	$11,472
Distribution	367-UG Conductors & Devices	8.71%	$10,668	0.00%	$0	$10,668	7.61%	$10,428	$21,096
Distribution	368-Line Transformers	16.17%	$19,806	0.00%	$0	$19,806	13.51%	$18,524	$38,331
Distribution	369-Services	3.16%	$3,877	0.00%	$0	$3,877	4.33%	$5,937	$9,814
Distribution	370-Meters	1.91%	$2,341	0.00%	$0	$2,341	2.54%	$3,479	$5,820
Distribution	373-Street Lighting & Signals	1.08%	$1,321	0.00%	$0	$1,321	1.39%	$1,908	$3,229
	Total Distribution		$101,727		$0	$101,727		$119,188	$220,915
General	389-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
General	390-Struct & Imprv	0.32%	$387	1.02%	$3,288	$3,674	0.47%	$641	$4,315
General	391-Furn & Eq	2.04%	$2,504	0.00%	$0	$2,504	3.31%	$4,538	$7,042
General	392-Transp Eq	-0.29%	($351)	0.00%	$0	($351)	0.00%	$0	($351)
General	393-Stores Eq	0.02%	$28	0.00%	$0	$28	0.03%	$37	$65
General	394-Tools, Shp & Gar	0.50%	$616	0.00%	$0	$616	0.66%	$908	$1,524
General	395-Lab Eq	0.26%	$322	0.00%	$0	$322	0.22%	$305	$627
General	396-Power Op Eq	0.29%	$357	0.00%	$0	$357	0.15%	$201	$558
General	397-Comm Eq	0.59%	$726	0.00%	$0	$726	0.47%	$641	$1,368
General	398-Misc Eq	0.05%	$57	0.00%	$0	$57	0.03%	$42	$99
	Total General		$4,647		$3,288	$7,934		$7,313	$15,247
	Total		$122,500		$323,410	$445,909		$137,076	$582,985

UNS Electric, Inc.
Depreciation by Plant FERC Account
Test Year Ended June 30, 2006

Source: Eric Fowler 9/19/06 (this table is taken from the Revenue Requirement Model on 11/14/06)

		Grand Total					% of Total	% of Total	% of Total
Function	Plt Acct & Desc	0403	0404	403 & 404	0406	Sum	403	404	406
Intangible	302-Franchises & Consents	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Intangible	303-Intangibles	$0.00	$386,336.30	$386,336.30	$289,869.21	$676,205.51	0.00%	98.98%	-7.40%
	Total Intangible	$0.00	$386,336.30	$386,336.30	$289,869.21	$676,205.51	0.00%	98.98%	-7.40%
Other Production	340-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Other Production	341-Struct & Imprv	$8,545.56	$0.00	$8,545.56	($2,069.16)	$6,476.40	0.06%	0.00%	0.05%
Other Production	342-Fuel Holders and Accessories	$15,279.00	$0.00	$15,279.00	($7,293.60)	$7,985.40	0.11%	0.00%	0.19%
Other Production	343-Prime Movers	$203,207.40	$0.00	$203,207.40	($84,240.36)	$118,967.04	1.42%	0.00%	2.15%
Other Production	344-Generators	$15,471.24	$0.00	$15,471.24	($7,722.48)	$7,748.76	0.11%	0.00%	0.20%
Other Production	345-Accessory Elec Eq	$37,074.36	$0.00	$37,074.36	($16,043.52)	$21,030.84	0.26%	0.00%	0.41%
Other Production	346-Misc Pwr Plt Eq	$9,237.36	$0.00	$9,237.36	($4,578.00)	$4,659.36	0.06%	0.00%	0.12%
	Total Other Production	$288,814.92	$0.00	$288,814.92	($121,947.12)	$166,867.80	2.02%	0.00%	3.11%
Transmission	350-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Transmission	352-Str & Impr	$7,225.56	$0.00	$7,225.56	($1,267.92)	$5,957.64	0.05%	0.00%	0.03%
Transmission	353-Station Eq	$518,281.56	$0.00	$518,281.56	($172,626.72)	$345,654.84	3.62%	0.00%	4.41%
Transmission	354-Towers & Fixtures	$21,299.76	$0.00	$21,299.76	($10,192.20)	$11,107.56	0.15%	0.00%	0.26%
Transmission	355-Poles & Fixtures	$733,454.57	$0.00	$733,454.57	($184,069.68)	$549,384.89	5.13%	0.00%	4.70%
Transmission	356-OH Conduct & Devices	$310,841.93	$0.00	$310,841.93	($100,769.40)	$210,072.53	2.17%	0.00%	2.57%
Transmission	358-UG Conductors & Devices	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Transmission	359-Roads & Trails	$3,695.52	$0.00	$3,695.52	($1,323.24)	$2,372.28	0.03%	0.00%	0.03%
	Total Transmission	$1,594,798.90	$0.00	$1,594,798.90	($470,249.16)	$1,124,549.74	11.15%	0.00%	12.00%
Distribution	360-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Distribution	361-Struct & Imprv	$126,971.87	$0.00	$126,971.87	($49,981.92)	$76,989.95	0.89%	0.00%	1.28%
Distribution	362-Station Eq	$1,383,463.45	$0.00	$1,383,463.45	($465,075.12)	$918,388.33	9.67%	0.00%	11.87%
Distribution	364-Poles, Towers & Fixtures	$3,231,613.80	$0.00	$3,231,613.80	($958,340.40)	$2,273,273.40	22.59%	0.00%	24.46%
Distribution	365-OH Conduct & Devices	$2,148,737.79	$0.00	$2,148,737.79	($589,444.32)	$1,559,293.47	15.02%	0.00%	15.04%
Distribution	366-UG Conduit	$551,074.38	$0.00	$551,074.38	($193,072.44)	$358,001.94	3.85%	0.00%	4.93%
Distribution	367-UG Conductors & Devices	$1,246,005.58	$0.00	$1,246,005.58	($298,124.28)	$947,881.30	8.71%	0.00%	7.61%
Distribution	368-Line Transformers	$2,313,392.75	$0.00	$2,313,392.75	($529,577.28)	$1,783,815.47	16.17%	0.00%	13.51%
Distribution	369-Services	$452,792.08	$0.00	$452,792.08	($169,727.40)	$283,064.68	3.16%	0.00%	4.33%
Distribution	370-Meters	$273,475.29	$0.00	$273,475.29	($99,460.44)	$174,014.85	1.91%	0.00%	2.54%
Distribution	373-Street Lighting & Signals	$154,301.97	$0.00	$154,301.97	($54,551.64)	$99,750.33	1.08%	0.00%	1.39%
	Total Distribution	$11,881,828.96	$0.00	$11,881,828.96	($3,407,355.24)	$8,474,473.72	83.04%	0.00%	86.95%
General	389-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
General	390-Struct & Imprv	$45,162.69	$3,968.04	$49,130.73	($18,317.76)	$30,812.97	0.32%	1.02%	0.47%
General	391-Furn & Eq	$292,500.08	$0.00	$292,500.08	($129,733.59)	$162,766.49	2.04%	0.00%	3.31%
General	392-Transp Eq	($40,958.88)	$0.00	($40,958.88)	$0.00	($40,958.88)	-0.29%	0.00%	0.00%
General	393-Stores Eq	$3,219.12	$0.00	$3,219.12	($1,062.00)	$2,157.12	0.02%	0.00%	0.03%
General	394-Tools, Shp & Gar	$71,986.90	$0.00	$71,986.90	($25,945.80)	$46,041.10	0.50%	0.00%	0.66%
General	395-Lab Eq	$37,641.04	$0.00	$37,641.04	($8,721.36)	$28,919.68	0.26%	0.00%	0.22%
General	396-Power Op Eq	$41,750.81	$0.00	$41,750.81	($5,736.60)	$36,014.21	0.29%	0.00%	0.15%
General	397-Comm Eq	$84,837.01	$0.00	$84,837.01	($18,331.08)	$66,505.93	0.59%	0.00%	0.47%
General	398-Misc Eq	$6,622.53	$0.00	$6,622.53	($1,201.80)	$5,420.73	0.05%	0.00%	0.03%
	Total General	$542,761.30	$3,968.04	$546,729.34	($209,049.99)	$337,679.35	3.79%	1.02%	5.33%
	Total Expense	$14,308,204.08	$390,304.34	$14,698,508.42	($3,918,732.30)	$10,779,776.12	100.00%	100.00%	100.00%

UNS Electric, Inc.
Depreciation Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
Intangible Plant:					
Acct. 302 Franchises and Consents	11,908	337	12,245	4.00%	490
Acct. 303 Misc. Intangible - WAPA Switchyard	3,466,687	98,123	3,564,810	3.13%	111,579
Acct. 303 Misc. Intangible - PC Software	1,151,869	32,603	1,184,472	20.00%	236,894
Acct. 303 Misc. Intangible - WAPA Fiber Optic	1,685,000	47,693	1,732,693	4.35%	75,372
Acct. 303 Misc. Intangible Plant	4,219,098	119,419	4,338,517	6.67%	289,379
Total	10,534,562	298,175	10,832,737		713,714
Other Production Plant:					
Acct. 340 Land & Land Rights	765,874	21,678	787,552	0.00%	-
Acct. 341 Structures & Improvements	1,141,496	32,309	1,173,805	2.07%	24,298
Acct. 342 Fuel Holders, Products & Access.	1,163,837	32,942	1,196,779	2.51%	30,039
Acct. 343 Prime Movers	15,413,970	436,285	15,850,255	2.53%	401,011
Acct. 344 Generators	4,850,576	137,293	4,987,869	2.33%	116,217
Acct. 345 Accessory Elec. Equipment	3,106,439	87,926	3,194,365	2.35%	75,068
Acct. 346 Misc. Power Plant Equip.	910,585	25,774	936,359	2.64%	24,720
Total	27,352,777	774,207	28,126,984		671,353
Transmission Plant:					
Acct. 350 Land	931,974	26,379	958,353	0.00%	-
Acct. 350 Land Rights	346,016	9,794	355,810	2.02%	7,187
Acct. 352 Structures & Improvements	191,668	5,425	197,093	3.13%	6,169
Acct. 353 Station Equipment	17,749,374	502,387	18,251,761	3.15%	574,930
Acct. 354 Towers & Fixtures	521,825	14,770	536,595	5.03%	26,991
Acct. 355 Poles & Fixtures	12,270,355	347,306	12,617,661	4.48%	565,271
Acct. 356 Overhead Conductors & Devices	11,237,572	318,074	11,555,646	2.66%	307,380
Acct. 359 Roads & Trails	183,860	5,204	189,064	2.02%	3,819
Total	43,432,644	1,229,339	44,661,983		1,491,747
Distribution Plant:					
Acct. 360 Land	1,147,687	32,485	1,180,172	0.00%	-
Acct. 360 Land Rights	90,198	2,553	92,751	2.03%	1,883
Acct. 361 Structures & Improvements	4,079,497	115,468	4,194,965	2.96%	124,171
Acct. 362 Station Equipment	32,948,469	932,590	33,881,059	4.09%	1,385,735
Acct. 364 Poles, Towers, and Fixtures	76,284,703	2,159,199	78,443,902	4.14%	3,247,578
Acct. 365 Overhead Conductors & Devices	49,721,006	1,407,328	51,128,334	4.13%	2,111,600
Acct. 366 Undeground Conduit	12,601,063	356,667	12,957,730	3.79%	491,098
Acct. 367 Underground Conductors & Devices	27,259,007	771,552	28,030,559	4.40%	1,233,345
Acct. 368 Line Transformers	47,498,916	1,344,432	48,843,348	4.63%	2,261,447
Acct. 369 Services (Overhead)	7,345,320	207,906	7,553,226	3.77%	284,757
Acct. 369 Services (Underground)	3,350,247	94,827	3,445,074	3.75%	129,190
Acct. 370 Meters	9,796,741	277,292	10,074,033	3.11%	313,302
Acct. 373 St. Lghtng & Signal Systems	3,811,070	107,870	3,918,940	4.04%	158,325
Total	275,933,924	7,810,169	283,744,093		11,742,431

UNS Electric, Inc.
Depreciation Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
General Plant:					
Acct. 389 Land & Land Rights	57,580	1,630	59,210	0.00%	-
Acct. 390 Structures & Improvements	1,852,505	52,434	1,904,939	2.65%	50,481
Acct. 391 Office Furniture & Equipment	2,300,322	65,109	2,365,431	4.76%	112,595
Acct. 391 Computer Equipment - PCs	920,167	26,045	946,212	20.00%	189,242
Acct. 392 Transportation Equipment - Class 1	366,331	10,369	376,700	12.75%	48,029
Acct. 392 Transportation Equipment - Class 2	1,151,599	32,595	1,184,194	16.99%	201,195
Acct. 392 Transportation Equipment - Class 3	1,185,238	33,548	1,218,786	20.21%	246,317
Acct. 392 Transportation Equipment - Class 4	5,641,612	159,683	5,801,295	13.47%	781,434
Acct. 392 Transportation Equipment - Class 5	1,995,626	56,485	2,052,111	12.55%	257,540
Acct. 393 Stores Equipment	122,871	3,478	126,349	3.03%	3,828
Acct. 394 Tools, Shop, & Garage Equip.	2,442,774	69,141	2,511,915	3.45%	86,661
Acct. 395 Laboratory Equipment	1,308,029	37,023	1,345,052	2.50%	33,626
Acct. 396 Power Operated Equip.	1,209,325	34,229	1,243,554	6.92%	86,054
Acct. 397 Communications Equip.	2,262,795	64,047	2,326,842	4.35%	101,218
Acct. 398 Misc. Equipment	121,811	3,448	125,259	5.56%	6,964
Total	22,938,585	649,264	23,587,849		2,205,184

	Total Annualized Depreciation	16,824,429
	Less: Previously Recognized Depreciation on CWIP Requested in Rate Base	(449,816)
Pro Forma Acct. 392 Depreciation X 58.5%	Less: Vehicle Depreciation Charged to CWIP	(897,691)
	Total Annualized Depreciation Expense	15,476,922
	Test Year Recorded Depreciation Expense	14,698,509
Test Year Acct. 392 depreciation X 41.5%	Add: Vehicle Depreciation cleared to O&M	332,503
	Test Year Depreciation Expense	15,031,012
	Adjustment Required	445,910

	Acct. 403	Acct. 404	O&M Exp.	Total
Test Year Recorded	14,308,205	390,304	332,503	15,031,012
T.Y. As Adjusted -				
Annualized	16,110,715	713,714		16,824,429
Less; Depr. On CWIP previously recognized	(449,816)			(449,816)
Vehicle Depreciation Chgs CWIP	(1,534,515)		636,824	(897,691)
	14,126,384	713,714	636,824	15,476,922
Adjustment amount	(181,821)	323,410	304,321	445,910

Net 403 122,500

Note--for purposes of the adjustment, vehicle depreciation in O&M is treated as being in Acct. 403

UNS Electric, Inc.
Acquisition Discount Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
Intangible Plant:					
Acct. 302 Franchises and Consents	(6,563)	670	(5,893)	4.00%	(236)
Acct. 303 Misc. Intangible - WAPA Switchyard	-	-	-	3.13%	-
Acct. 303 Misc. Intangible - PC Software	(283,245)	28,910	(254,335)	20.00%	(50,867)
Acct. 303 Misc. Intangible - WAPA Fiber Optic	-	-	-	4.35%	-
Acct. 303 Misc. Intangible Plant	(2,178,032)	222,305	(1,955,727)	6.67%	(130,447)
Total	(2,467,840)	251,885	(2,215,955)		(181,550)
Other Production Plant:					
Acct. 340 Land & Land Rights	(422,116)	43,084	(379,032)	0.00%	-
Acct. 341 Structures & Improvements	(149,938)	15,304	(134,634)	2.07%	(2,787)
Acct. 342 Fuel Holders, Products & Access.	(301,386)	30,762	(270,624)	2.51%	(6,793)
Acct. 343 Prime Movers	(3,600,013)	367,442	(3,232,571)	2.53%	(81,784)
Acct. 344 Generators	(1,152,606)	117,643	(1,034,963)	2.33%	(24,115)
Acct. 345 Accessory Elec. Equipment	(729,249)	74,432	(654,817)	2.35%	(15,388)
Acct. 346 Misc. Power Plant Equip.	(244,813)	24,987	(219,826)	2.64%	(5,803)
Total	(6,600,121)	673,654	(5,926,467)		(136,670)
Transmission Plant:					
Acct. 350 Land	(513,664)	52,428	(461,236)	0.00%	-
Acct. 350 Land Rights	(190,708)	19,465	(171,243)	2.02%	(3,459)
Acct. 352 Structures & Improvements	(33,630)	3,433	(30,197)	3.13%	(945)
Acct. 353 Station Equipment	(5,911,873)	603,407	(5,308,466)	3.15%	(167,217)
Acct. 354 Towers & Fixtures	(236,215)	24,110	(212,105)	5.03%	(10,669)
Acct. 355 Poles & Fixtures	(3,190,115)	325,605	(2,864,510)	4.48%	(128,330)
Acct. 356 Overhead Conductors & Devices	(3,718,427)	379,529	(3,338,898)	2.66%	(88,815)
Acct. 359 Roads & Trails	(65,832)	6,719	(59,113)	2.02%	(1,194)
Total	(13,860,464)	1,414,696	(12,445,768)		(400,629)
Distribution Plant:					
Acct. 360 Land	(595,245)	60,755	(534,490)	0.00%	-
Acct. 360 Land Rights	(47,740)	4,873	(42,867)	2.03%	(870)
Acct. 361 Structures & Improvements	(1,561,939)	159,422	(1,402,517)	2.96%	(41,515)
Acct. 362 Station Equipment	(9,648,864)	984,830	(8,664,034)	4.09%	(354,359)
Acct. 364 Poles, Towers, and Fixtures	(22,655,802)	2,312,406	(20,343,396)	4.14%	(842,217)
Acct. 365 Overhead Conductors & Devices	(13,519,363)	1,379,880	(12,139,483)	4.13%	(501,361)
Acct. 366 Undeground Conduit	(4,511,041)	460,428	(4,050,613)	3.79%	(153,518)
Acct. 367 Underground Conductors & Devices	(5,562,021)	567,698	(4,994,323)	4.40%	(219,750)
Acct. 368 Line Transformers	(10,741,931)	1,096,396	(9,645,535)	4.63%	(446,588)
Acct. 369 Services (Overhead)	(2,577,155)	263,042	(2,314,113)	3.77%	(87,242)
Acct. 369 Services (Underground)	(1,435,315)	146,498	(1,288,817)	3.75%	(48,331)
Acct. 370 Meters	(3,060,324)	312,358	(2,747,966)	3.11%	(85,462)
Acct. 373 St. Lghtng & Signal Systems	(1,198,936)	122,372	(1,076,564)	4.04%	(43,493)
Total	(77,115,676)	7,870,958	(69,244,718)		(2,824,706)

UNS Electric, Inc.
Acquisition Discount Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
General Plant:					
Acct. 389 Land & Land Rights	(31,736)	3,239	(28,497)	0.00%	-
Acct. 390 Structures & Improvements	(633,826)	64,693	(569,133)	2.65%	(15,082)
Acct. 391 Office Furniture & Equipment	(460,920)	47,045	(413,875)	4.76%	(19,700)
Acct. 391 Computer Equipment - PCs	(673,037)	68,695	(604,342)	20.00%	(120,868)
Acct. 392 Transportation Equipment - Class 1	(51,192)	39,563	(11,629)	12.75%	(1,483)
Acct. 392 Transportation Equipment - Class 2	(16,191)	12,513	(3,678)	16.99%	(625)
Acct. 392 Transportation Equipment - Class 3	(92,982)	71,860	(21,122)	20.21%	(4,269)
Acct. 392 Transportation Equipment - Class 4	(362,404)	280,080	(82,324)	13.47%	(11,089)
Acct. 392 Transportation Equipment - Class 5	-	-	-	12.55%	-
Acct. 393 Stores Equipment	(40,540)	4,138	(36,402)	3.03%	(1,103)
Acct. 394 Tools, shop, & Garage Equip.	(859,128)	87,689	(771,439)	3.45%	(26,615)
Acct. 395 Laboratory Equipment	(361,880)	36,936	(324,944)	2.50%	(8,124)
Acct. 396 Power Operated Equip.	(172,278)	17,584	(154,694)	6.92%	(10,705)
Acct. 397 Communications Equip.	(443,854)	45,303	(398,551)	4.35%	(17,337)
Acct. 398 Misc. Equipment	(22,054)	2,251	(19,803)	5.56%	(1,101)
Total	(4,222,022)	781,589	(3,440,433)		(238,101)

Total Annualized Amortization-Acq. Discount	(3,781,656)
Test Year Amount per Books	(3,918,732)
Adjustment Required (FERC 406)	137,076

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Depreciation Annualization - Detail by FERC
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	November 28, 2006
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
FERC 403 & 404			
303	Miscellaneous Intangible Plant	$320,122	
341	Structures & Improvements	$34	
342	Fuel Holders, Producers, & Accessories	$62	
343	Prime Movers	$818	
344	Generators	$62	
345	Accessory Electric Equipment	$149	
346	Misc. Power Plant Equipment	$37	
352	Structures & Improvements	$29	
353	Station Equipment	$2,087	
354	Towers & Fixtures	$86	
355	Poles & Fixtures	$2,954	
356	Overhead Conductors & Devices	$1,252	
359	Roads & Trails	$15	
361	Structures & Improvements	$511	
362	Station Equipment	$5,572	
364	Poles, Towers, & Fixtures	$13,016	
365	Overhead Conductors & Devices	$8,654	
366	Underground Conduit	$2,220	
367	Underground Conductors & Devices	$5,018	
368	Line Transformers	$9,317	
369	Services	$1,824	
370	Meters	$1,101	
373	Street Lights and Signal Systems	$621	
390	Structures & Improvements	$3,469	
391	Office Furniture & Equipment	$1,178	
392	Transportation Equipment		$165
393	Stores Equipment	$13	
394	Tools, Shop, & Garage Equipment	$290	
395	Laboratory Equipment	$152	
396	Power Operated Equipment	$168	
397	Communication Equipment	$342	
398	Miscellaneous Equipment	$27	
FERC 406			
303	Miscellaneous Intangible Plant		$10,270
341	Structures & Improvements	$73	
342	Fuel Holders, Producers, & Accessories	$258	
343	Prime Movers	$2,985	
344	Generators	$274	
345	Accessory Electric Equipment	$568	
346	Misc. Power Plant Equipment	$162	
352	Structures & Improvements	$45	
353	Station Equipment	$6,116	
354	Towers & Fixtures	$361	

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Depreciation Annualization - Detail by FERC
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	November 28, 2006
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
355	Poles & Fixtures	$6,522	
356	Overhead Conductors & Devices	$3,570	
359	Roads & Trails	$47	
361	Structures & Improvements	$1,771	
362	Station Equipment	$16,478	
364	Poles, Towers, & Fixtures	$33,955	
365	Overhead Conductors & Devices	$20,884	
366	Underground Conduit	$6,841	
367	Underground Conductors & Devices	$10,563	
368	Line Transformers	$18,763	
369	Services	$6,014	
370	Meters	$3,524	
373	Street Lights and Signal Systems	$1,933	
390	Structures & Improvements	$649	
391	Office Furniture & Equipment	$4,597	
393	Stores Equipment	$38	
394	Tools, Shop, & Garage Equipment	$919	
395	Laboratory Equipment	$309	
396	Power Operated Equipment	$203	
397	Communication Equipment	$649	
398	Miscellaneous Equipment	$43	
	ENTRY TOTAL	**$530,312**	**$10,436**

NET ENTRY **$519,876**

(rounding variance of $5 with unallocated amounts is ignored - immaterial)

Reason for Adjustment

To adjust test year recorded depreciation to reflect annualized depreciation based on ending plant balances and the depreciation rates resulting from Dr. White's study. This adjustment excludes the effects of depreciation on the level of CWIP requested for inclusion in rate base.

To adjust test year recorded amortization expense to reflect acquisition discount in Decision No. 66028 and the depreciation rates resulting from Dr. White's study.

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Depreciation Annualization - Summary by FERC
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	November 26, 2006
PREPARED BY:	E. Fowler
CHECKED BY:	C. Dabelstein
REVIEWED BY:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
403	Depreciation Expense	$57,628	
404	Amortization of Utility Plant	$323,410	
406	Amortization of Utility Plant Acquisition Adjustments	$138,843	
	ENTRY TOTAL	**$519,881**	**$0**

Reason for Adjustment

To adjust test year recorded depreciation and amortization expense to reflect the final adjusted balances

UNS Electric, Inc.
Allocation of Depreciation & Amortization Pro Forma Adjustment to FERC Accounts
Test Year Ended June 30, 2006

Function	Plt Acct & Desc	403 %	403 $57,628	403 %	404 $323,410	Total 403 & 404 $381,038	406 %	406 $138,843	Total $519,881
Intangible	302-Franchises & Consents	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Intangible	303-Intangibles	0.00%	$0	98.98%	$320,122	$320,122	-7.40%	($10,270)	$309,852
	Total Intangible		$0		$320,122	$320,122		($10,270)	$309,852
Other Production	340-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Other Production	341-Struct & Imprv	0.06%	$34	0.00%	$0	$34	0.05%	$73	$108
Other Production	342-Fuel Holders and Accessories	0.11%	$62	0.00%	$0	$62	0.19%	$258	$320
Other Production	343-Prime Movers	1.42%	$818	0.00%	$0	$818	2.15%	$2,985	$3,803
Other Production	344-Generators	0.11%	$62	0.00%	$0	$62	0.20%	$274	$336
Other Production	345-Accessory Elec Eq	0.26%	$149	0.00%	$0	$149	0.41%	$568	$718
Other Production	346-Misc Pwr Plt Eq	0.06%	$37	0.00%	$0	$37	0.12%	$162	$199
	Total Other Production		$1,163		$0	$1,163		$4,321	$5,484
Transmission	350-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Transmission	352-Str & Impr	0.05%	$29	0.00%	$0	$29	0.03%	$45	$74
Transmission	353-Station Eq	3.62%	$2,087	0.00%	$0	$2,087	4.41%	$6,116	$8,203
Transmission	354-Towers & Fixtures	0.15%	$86	0.00%	$0	$86	0.26%	$361	$447
Transmission	355-Poles & Fixtures	5.13%	$2,954	0.00%	$0	$2,954	4.70%	$6,522	$9,476
Transmission	356-OH Conduct & Devices	2.17%	$1,252	0.00%	$0	$1,252	2.57%	$3,570	$4,822
Transmission	358-UG Conductors & Devices	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Transmission	359-Roads & Trails	0.03%	$15	0.00%	$0	$15	0.03%	$47	$62
	Total Transmission		$6,423		$0	$6,423		$16,661	$23,084
Distribution	360-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Distribution	361-Struct & Imprv	0.89%	$511	0.00%	$0	$511	1.28%	$1,771	$2,282
Distribution	362-Station Eq	9.67%	$5,572	0.00%	$0	$5,572	11.87%	$16,478	$22,050
Distribution	364-Poles, Towers & Fixtures	22.59%	$13,016	0.00%	$0	$13,016	24.46%	$33,955	$46,970
Distribution	365-OH Conduct & Devices	15.02%	$8,654	0.00%	$0	$8,654	15.04%	$20,884	$29,539
Distribution	366-UG Conduit	3.85%	$2,220	0.00%	$0	$2,220	4.93%	$6,841	$9,060
Distribution	367-UG Conductors & Devices	8.71%	$5,018	0.00%	$0	$5,018	7.61%	$10,563	$15,581
Distribution	368-Line Transformers	16.17%	$9,317	0.00%	$0	$9,317	13.51%	$18,763	$28,081
Distribution	369-Services	3.16%	$1,824	0.00%	$0	$1,824	4.33%	$6,014	$7,837
Distribution	370-Meters	1.91%	$1,101	0.00%	$0	$1,101	2.54%	$3,524	$4,625
Distribution	373-Street Lighting & Signals	1.08%	$621	0.00%	$0	$621	1.39%	$1,933	$2,554
	Total Distribution		$47,855		$0	$47,855		$120,725	$168,580
General	389-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
General	390-Struct & Imprv	0.32%	$182	1.02%	$3,288	$3,469	0.47%	$649	$4,118
General	391-Furn & Eq	2.04%	$1,178	0.00%	$0	$1,178	3.31%	$4,597	$5,775
General	392-Transp Eq	-0.29%	($165)	0.00%	$0	($165)	0.00%	$0	($165)
General	393-Stores Eq	0.02%	$13	0.00%	$0	$13	0.03%	$38	$51
General	394-Tools, Shp & Gar	0.50%	$290	0.00%	$0	$290	0.66%	$919	$1,209
General	395-Lab Eq	0.26%	$152	0.00%	$0	$152	0.22%	$309	$461
General	396-Power Op Eq	0.29%	$168	0.00%	$0	$168	0.15%	$203	$371
General	397-Comm Eq	0.59%	$342	0.00%	$0	$342	0.47%	$649	$991
General	398-Misc Eq	0.05%	$27	0.00%	$0	$27	0.03%	$43	$69
	Total General		$2,186		$3,288	$5,473		$7,407	$12,880
	Total		$57,628		$323,410	$381,037		$138,843	$519,880

UNS Electric, Inc.
Depreciation by Plant FERC Account
Test Year Ended June 30, 2006

Source: Eric Fowler 9/19/06 (this table is taken from the Revenue Requirement Model on 11/14/06)

		Grand Total					% of Total	% of Total	% of Total
Function	Plt Acct & Desc	0403	0404	403 & 404	0406	Sum	403	404	406
Intangible	302-Franchises & Consents	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Intangible	303-Intangibles	$0.00	$386,336.30	$386,336.30	$289,869.21	$676,205.51	0.00%	98.98%	-7.40%
	Total Intangible	$0.00	$386,336.30	$386,336.30	$289,869.21	$676,205.51	0.00%	98.98%	-7.40%
Other Production	340-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Other Production	341-Struct & Imprv	$8,545.56	$0.00	$8,545.56	($2,069.16)	$6,476.40	0.06%	0.00%	0.05%
Other Production	342-Fuel Holders and Accessories	$15,279.00	$0.00	$15,279.00	($7,293.60)	$7,985.40	0.11%	0.00%	0.19%
Other Production	343-Prime Movers	$203,207.40	$0.00	$203,207.40	($84,240.36)	$118,967.04	1.42%	0.00%	2.15%
Other Production	344-Generators	$15,471.24	$0.00	$15,471.24	($7,722.48)	$7,748.76	0.11%	0.00%	0.20%
Other Production	345-Accessory Elec Eq	$37,074.36	$0.00	$37,074.36	($16,043.52)	$21,030.84	0.26%	0.00%	0.41%
Other Production	346-Misc Pwr Plt Eq	$9,237.36	$0.00	$9,237.36	($4,578.00)	$4,659.36	0.06%	0.00%	0.12%
	Total Other Production	$288,814.92	$0.00	$288,814.92	($121,947.12)	$166,867.80	2.02%	0.00%	3.11%
Transmission	350-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Transmission	352-Str & Impr	$7,225.56	$0.00	$7,225.56	($1,267.92)	$5,957.64	0.05%	0.00%	0.03%
Transmission	353-Station Eq	$518,281.56	$0.00	$518,281.56	($172,626.72)	$345,654.84	3.62%	0.00%	4.41%
Transmission	354-Towers & Fixtures	$21,299.76	$0.00	$21,299.76	($10,192.20)	$11,107.56	0.15%	0.00%	0.26%
Transmission	355-Poles & Fixtures	$733,454.57	$0.00	$733,454.57	($184,069.68)	$549,384.89	5.13%	0.00%	4.70%
Transmission	356-OH Conduct & Devices	$310,841.93	$0.00	$310,841.93	($100,769.40)	$210,072.53	2.17%	0.00%	2.57%
Transmission	358-UG Conductors & Devices	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Transmission	359-Roads & Trails	$3,695.52	$0.00	$3,695.52	($1,323.24)	$2,372.28	0.03%	0.00%	0.03%
	Total Transmission	$1,594,798.90	$0.00	$1,594,798.90	($470,249.16)	$1,124,549.74	11.15%	0.00%	12.00%
Distribution	360-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Distribution	361-Struct & Imprv	$126,971.87	$0.00	$126,971.87	($49,981.92)	$76,989.95	0.89%	0.00%	1.28%
Distribution	362-Station Eq	$1,383,463.45	$0.00	$1,383,463.45	($465,075.12)	$918,388.33	9.67%	0.00%	11.87%
Distribution	364-Poles, Towers & Fixtures	$3,231,613.80	$0.00	$3,231,613.80	($958,340.40)	$2,273,273.40	22.59%	0.00%	24.46%
Distribution	365-OH Conduct & Devices	$2,148,737.79	$0.00	$2,148,737.79	($589,444.32)	$1,559,293.47	15.02%	0.00%	15.04%
Distribution	366-UG Conduit	$551,074.38	$0.00	$551,074.38	($193,072.44)	$358,001.94	3.85%	0.00%	4.93%
Distribution	367-UG Conductors & Devices	$1,246,005.58	$0.00	$1,246,005.58	($298,124.28)	$947,881.30	8.71%	0.00%	7.61%
Distribution	368-Line Transformers	$2,313,392.75	$0.00	$2,313,392.75	($529,577.28)	$1,783,815.47	16.17%	0.00%	13.51%
Distribution	369-Services	$452,792.08	$0.00	$452,792.08	($169,727.40)	$283,064.68	3.16%	0.00%	4.33%
Distribution	370-Meters	$273,475.29	$0.00	$273,475.29	($99,460.44)	$174,014.85	1.91%	0.00%	2.54%
Distribution	373-Street Lighting & Signals	$154,301.97	$0.00	$154,301.97	($54,551.64)	$99,750.33	1.08%	0.00%	1.39%
	Total Distribution	$11,881,828.96	$0.00	$11,881,828.96	($3,407,355.24)	$8,474,473.72	83.04%	0.00%	86.95%
General	389-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
General	390-Struct & Imprv	$45,162.69	$3,968.04	$49,130.73	($18,317.76)	$30,812.97	0.32%	1.02%	0.47%
General	391-Furn & Eq	$292,500.08	$0.00	$292,500.08	($129,733.59)	$162,766.49	2.04%	0.00%	3.31%
General	392-Transp Eq	($40,958.88)	$0.00	($40,958.88)	$0.00	($40,958.88)	-0.29%	0.00%	0.00%
General	393-Stores Eq	$3,219.12	$0.00	$3,219.12	($1,062.00)	$2,157.12	0.02%	0.00%	0.03%
General	394-Tools, Shp & Gar	$71,986.90	$0.00	$71,986.90	($25,945.80)	$46,041.10	0.50%	0.00%	0.66%
General	395-Lab Eq	$37,641.04	$0.00	$37,641.04	($8,721.36)	$28,919.68	0.26%	0.00%	0.22%
General	396-Power Op Eq	$41,750.81	$0.00	$41,750.81	($5,736.60)	$36,014.21	0.29%	0.00%	0.15%
General	397-Comm Eq	$84,837.01	$0.00	$84,837.01	($18,331.08)	$66,505.93	0.59%	0.00%	0.47%
General	398-Misc Eq	$6,622.53	$0.00	$6,622.53	($1,201.80)	$5,420.73	0.05%	0.00%	0.03%
	Total General	$542,761.30	$3,968.04	$546,729.34	($209,049.99)	$337,679.35	3.79%	1.02%	5.33%
	Total Expense	$14,308,204.08	$390,304.34	$14,698,508.42	($3,918,732.30)	$10,779,776.12	100.00%	100.00%	100.00%

UNS Electric, Inc.
Depreciation Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
Intangible Plant:					
Acct. 302 Franchises and Consents	11,908	337	12,245	4.00%	490
Acct. 303 Misc. Intangible - WAPA Switchyard	3,466,687	98,123	3,564,810	3.13%	111,579
Acct. 303 Misc. Intangible - PC Software	1,151,869	32,603	1,184,472	20.00%	236,894
Acct. 303 Misc. Intangible - WAPA Fiber Optic	1,685,000	47,693	1,732,693	4.35%	75,372
Acct. 303 Misc. Intangible Plant	4,219,098	119,419	4,338,517	6.67%	289,379
Total	10,534,562	298,175	10,832,737		713,714
Other Production Plant:					
Acct. 340 Land & Land Rights	765,874	21,678	787,552	0.00%	-
Acct. 341 Structures & Improvements	1,141,496	32,309	1,173,805	2.07%	24,298
Acct. 342 Fuel Holders, Products & Access.	1,163,837	32,942	1,196,779	2.51%	30,039
Acct. 343 Prime Movers	15,413,970	436,285	15,850,255	2.53%	401,011
Acct. 344 Generators	4,850,576	137,293	4,987,869	2.33%	116,217
Acct. 345 Accessory Elec. Equipment	3,106,439	87,926	3,194,365	2.35%	75,068
Acct. 346 Misc. Power Plant Equip.	910,585	25,774	936,359	2.64%	24,720
Total	27,352,777	774,207	28,126,984		671,353
Transmission Plant:					
Acct. 350 Land	931,974	26,379	958,353	0.00%	-
Acct. 350 Land Rights	346,016	9,794	355,810	2.02%	7,187
Acct. 352 Structures & Improvements	191,668	5,425	197,093	3.13%	6,169
Acct. 353 Station Equipment	17,749,374	502,387	18,251,761	3.15%	574,930
Acct. 354 Towers & Fixtures	521,825	14,770	536,595	5.03%	26,991
Acct. 355 Poles & Fixtures	12,270,355	347,306	12,617,661	4.48%	565,271
Acct. 356 Overhead Conductors & Devices	11,237,572	318,074	11,555,646	2.66%	307,380
Acct. 359 Roads & Trails	183,860	5,204	189,064	2.02%	3,819
Total	43,432,644	1,229,339	44,661,983		1,491,747
Distribution Plant:					
Acct. 360 Land	1,147,687	32,485	1,180,172	0.00%	-
Acct. 360 Land Rights	90,198	2,553	92,751	2.03%	1,883
Acct. 361 Structures & Improvements	4,079,497	115,468	4,194,965	2.96%	124,171
Acct. 362 Station Equipment	32,948,469	932,590	33,881,059	4.09%	1,385,735
Acct. 364 Poles, Towers, and Fixtures	76,284,703	2,159,199	78,443,902	4.14%	3,247,578
Acct. 365 Overhead Conductors & Devices	49,721,006	1,407,328	51,128,334	4.13%	2,111,600
Acct. 366 Undeground Conduit	12,601,063	356,667	12,957,730	3.79%	491,098
Acct. 367 Underground Conductors & Devices	27,259,007	771,552	28,030,559	4.40%	1,233,345
Acct. 368 Line Transformers	47,498,916	1,344,432	48,843,348	4.63%	2,261,447
Acct. 369 Services (Overhead)	7,345,320	207,906	7,553,226	3.77%	284,757
Acct. 369 Services (Underground)	3,350,247	94,827	3,445,074	3.75%	129,190
Acct. 370 Meters	9,796,741	277,292	10,074,033	3.11%	313,302
Acct. 373 St. Lghtng & Signal Systems	3,811,070	107,870	3,918,940	4.04%	158,325
Total	275,933,924	7,810,169	283,744,093		11,742,431

UNS Electric, Inc.
Depreciation Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
General Plant:					
Acct. 389 Land & Land Rights	57,580	1,630	59,210	0.00%	-
Acct. 390 Structures & Improvements	1,852,505	52,434	1,904,939	2.65%	50,481
Acct. 391 Office Furniture & Equipment	2,300,322	65,109	2,365,431	4.76%	112,595
Acct. 391 Computer Equipment - PCs	920,167	26,045	946,212	20.00%	189,242
Acct. 392 Transportation Equipment - Class 1	366,331	10,369	376,700	11.48%	43,245
Acct. 392 Transportation Equipment - Class 2	1,151,599	32,595	1,184,194	15.29%	181,063
Acct. 392 Transportation Equipment - Class 3	1,185,238	33,548	1,218,786	18.69%	227,791
Acct. 392 Transportation Equipment - Class 4	5,641,612	159,683	5,801,295	11.97%	694,415
Acct. 392 Transportation Equipment - Class 5	1,995,626	56,485	2,052,111	11.29%	231,683
Acct. 393 Stores Equipment	122,871	3,478	126,349	3.03%	3,828
Acct. 394 Tools, Shop, & Garage Equip.	2,442,774	69,141	2,511,915	3.45%	86,661
Acct. 395 Laboratory Equipment	1,308,029	37,023	1,345,052	2.50%	33,626
Acct. 396 Power Operated Equip.	1,209,325	34,229	1,243,554	6.92%	86,054
Acct. 397 Communications Equip.	2,262,795	64,047	2,326,842	4.35%	101,218
Acct. 398 Misc. Equipment	121,811	3,448	125,259	5.56%	6,964
Total	22,938,585	649,264	23,587,849		2,048,866

	Total Annualized Depreciation	16,668,111
	Less: Previously Recognized Depreciation on CWIP Requested in Rate Base	(449,816)
Pro Forma Acct. 392 Depreciation X 58.5%	Less: Vehicle Depreciation Charged to CWIP	(806,245)
	Total Annualized Depreciation Expense	15,412,050
	Test Year Recorded Depreciation Expense	14,698,509
Test Year Acct. 392 depreciation X 41.5%	Add: Vehicle Depreciation cleared to O&M	332,503
	Test Year Depreciation Expense	15,031,012
	Adjustment Required	381,038

	Acct. 403	Acct. 404	O&M Exp.	Total
Test Year Recorded	14,308,205	390,304	332,503	15,031,012
T.Y. As Adjusted -				
Annualized	15,954,397	713,714		16,668,111
Less; Depr. On CWIP previously recognized	(449,816)			(449,816)
Vehicle Depreciation Chgs CWIP	(1,378,197)		571,952	(806,245)
	14,126,384	713,714	571,952	15,412,050
Adjustment amount	(181,821)	323,410	239,449	381,038

Net 403 57,628

Note--for purposes of the adjustment, vehicle depreciation in O&M is treated as being in Acct. 403

UNS Electric, Inc.
Acquisition Discount Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
Intangible Plant:					
Acct. 302 Franchises and Consents	(6,563)	670	(5,893)	4.00%	(236)
Acct. 303 Misc. Intangible - WAPA Switchyard	-	-	-	3.13%	-
Acct. 303 Misc. Intangible - PC Software	(283,245)	28,910	(254,335)	20.00%	(50,867)
Acct. 303 Misc. Intangible - WAPA Fiber Optic	-	-	-	4.35%	-
Acct. 303 Misc. Intangible Plant	(2,178,032)	222,305	(1,955,727)	6.67%	(130,447)
Total	(2,467,840)	251,885	(2,215,955)		(181,550)
Other Production Plant:					
Acct. 340 Land & Land Rights	(422,116)	43,084	(379,032)	0.00%	-
Acct. 341 Structures & Improvements	(149,938)	15,304	(134,634)	2.07%	(2,787)
Acct. 342 Fuel Holders, Products & Access.	(301,386)	30,762	(270,624)	2.51%	(6,793)
Acct. 343 Prime Movers	(3,600,013)	367,442	(3,232,571)	2.53%	(81,784)
Acct. 344 Generators	(1,152,606)	117,643	(1,034,963)	2.33%	(24,115)
Acct. 345 Accessory Elec. Equipment	(729,249)	74,432	(654,817)	2.35%	(15,388)
Acct. 346 Misc. Power Plant Equip.	(244,813)	24,987	(219,826)	2.64%	(5,803)
Total	(6,600,121)	673,654	(5,926,467)		(136,670)
Transmission Plant:					
Acct. 350 Land	(513,664)	52,428	(461,236)	0.00%	-
Acct. 350 Land Rights	(190,708)	19,465	(171,243)	2.02%	(3,459)
Acct. 352 Structures & Improvements	(33,630)	3,433	(30,197)	3.13%	(945)
Acct. 353 Station Equipment	(5,911,873)	603,407	(5,308,466)	3.15%	(167,217)
Acct. 354 Towers & Fixtures	(236,215)	24,110	(212,105)	5.03%	(10,669)
Acct. 355 Poles & Fixtures	(3,190,115)	325,605	(2,864,510)	4.48%	(128,330)
Acct. 356 Overhead Conductors & Devices	(3,718,427)	379,529	(3,338,898)	2.66%	(88,815)
Acct. 359 Roads & Trails	(65,832)	6,719	(59,113)	2.02%	(1,194)
Total	(13,860,464)	1,414,696	(12,445,768)		(400,629)
Distribution Plant:					
Acct. 360 Land	(595,245)	60,755	(534,490)	0.00%	-
Acct. 360 Land Rights	(47,740)	4,873	(42,867)	2.03%	(870)
Acct. 361 Structures & Improvements	(1,561,939)	159,422	(1,402,517)	2.96%	(41,515)
Acct. 362 Station Equipment	(9,648,864)	984,830	(8,664,034)	4.09%	(354,359)
Acct. 364 Poles, Towers, and Fixtures	(22,655,802)	2,312,406	(20,343,396)	4.14%	(842,217)
Acct. 365 Overhead Conductors & Devices	(13,519,363)	1,379,880	(12,139,483)	4.13%	(501,361)
Acct. 366 Undeground Conduit	(4,511,041)	460,428	(4,050,613)	3.79%	(153,518)
Acct. 367 Underground Conductors & Devices	(5,562,021)	567,698	(4,994,323)	4.40%	(219,750)
Acct. 368 Line Transformers	(10,741,931)	1,096,396	(9,645,535)	4.63%	(446,588)
Acct. 369 Services (Overhead)	(2,577,155)	263,042	(2,314,113)	3.77%	(87,242)
Acct. 369 Services (Underground)	(1,435,315)	146,498	(1,288,817)	3.75%	(48,331)
Acct. 370 Meters	(3,060,324)	312,358	(2,747,966)	3.11%	(85,462)
Acct. 373 St. Lghtng & Signal Systems	(1,198,936)	122,372	(1,076,564)	4.04%	(43,493)
Total	(77,115,676)	7,870,958	(69,244,718)		(2,824,706)

UNS Electric, Inc.
Acquisition Discount Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
General Plant:					
Acct. 389 Land & Land Rights	(31,736)	3,239	(28,497)	0.00%	-
Acct. 390 Structures & Improvements	(633,826)	64,693	(569,133)	2.65%	(15,082)
Acct. 391 Office Furniture & Equipment	(460,920)	47,045	(413,875)	4.76%	(19,700)
Acct. 391 Computer Equipment - PCs	(673,037)	68,695	(604,342)	20.00%	(120,868)
Acct. 392 Transportation Equipment - Class 1	(51,192)	39,563	(11,629)	11.48%	(1,335)
Acct. 392 Transportation Equipment - Class 2	(16,191)	12,513	(3,678)	15.29%	(562)
Acct. 392 Transportation Equipment - Class 3	(92,982)	71,860	(21,122)	18.69%	(3,948)
Acct. 392 Transportation Equipment - Class 4	(362,404)	280,080	(82,324)	11.97%	(9,854)
Acct. 392 Transportation Equipment - Class 5	-	-	-	11.29%	-
Acct. 393 Stores Equipment	(40,540)	4,138	(36,402)	3.03%	(1,103)
Acct. 394 Tools, shop, & Garage Equip.	(859,128)	87,689	(771,439)	3.45%	(26,615)
Acct. 395 Laboratory Equipment	(361,880)	36,936	(324,944)	2.50%	(8,124)
Acct. 396 Power Operated Equip.	(172,278)	17,584	(154,694)	6.92%	(10,705)
Acct. 397 Communications Equip.	(443,854)	45,303	(398,551)	4.35%	(17,337)
Acct. 398 Misc. Equipment	(22,054)	2,251	(19,803)	5.56%	(1,101)
Total	(4,222,022)	781,589	(3,440,433)		(236,334)

Total Annualized Amortization-Acq. Discount	(3,779,889)
Test Year Amount per Books	(3,918,732)
Adjustment Required (FERC 406)	138,843

UNS Electric, Inc.
Emergency Bill Assistance Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-16

Line No.	Description	Account	Amount	Reference
1	Increase to Emergency Bill Assistance Expense		$ 20,000	A

Notes and Source

A Testimony of Staff witnesses Ralph C. Smith and Julie McNeely-Kirwan

R14-2-102. Treatment of depreciation

A. The following definitions shall apply in this Section unless the context otherwise requires:

1. "Accumulated depreciation" means the summation of the annual provision for depreciation from the time that the asset is first devoted to public service.
2. "Cost of removal" means the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto.
3. "Depreciation" means an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life.
4. "Depreciation rate" means the percentage rate applied to the original cost of an asset to yield the annual provision for depreciation.
5. "Net salvage" means the salvage value of property retired less the cost of removal.
6. "Original cost" means the cost of property at the time it was first devoted to public service.
7. "Property retired" means assets which have been removed, sold, abandoned, destroyed, or which for any cause have been withdrawn from service and books of account.
8. "Salvage value" means the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; or if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate accounts.
9. "Service life" means the period between the date an asset is first devoted to public service and the date of its retirement from service.

B. All public service corporations shall maintain adequate accounts and records related to depreciation practices, subject to the following:

1. Annual depreciation accruals shall be recorded.
2. A separate reserve for each account or functional account shall be maintained.
3. The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systemic manner over the estimated service life of such plant.
4. Public service corporations having less than $250,000 in annual revenue shall not be required to maintain depreciation records by separate accounts but shall make annual composite accruals to accumulated depreciation for total depreciable plant.

C. Requests for depreciation rate changes and methods for estimating depreciation rates shall be as follows:

1. If a public service corporation seeks a change in its depreciation rates, it shall submit a request for such as part of a rate application in accordance with the requirements of R14-2-103.
2. A public service corporation may propose any reasonable method for estimating service lives, salvage values, and cost of removal. The method shall be fully described in a request to change depreciation rates.
3. Data and analyses supporting the change shall be submitted, including engineering data and assessment of the impact and appropriateness of the change for ratemaking purposes.
4. Changed depreciation rates shall not become effective until the Commission authorizes such changes.

D. Upon the motion of any party or upon its own motion, the Commission may determine that good cause exists for granting a waiver from one or more of the requirements of this Section.

Historical Note

Former Section R14-2-102 repealed, former Section R14-2-127 renumbered as Section R14-2-102 without change effective March 2, 1982 (Supp. 82-2). Forward to the rule corrected as filed April 13, 1973 (Supp. 89-1). Section R14-2-102 repealed, new Section adopted effective April 9, 1992 (Supp. 92-2).

Power Supply Adjustment
Plan of Administration

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1. General Description

This document describes the plan for administering the Power Supply Adjustment mechanism ("PSA") approved for Arizona Public Service Company ("APS") by the Commission on xxxxx, xx, 200x in Decision No. xxxxxxxx. This PSA replaces the Power Supply Adjustment mechanism approved in Decision No. 67744 ("the old PSA"). The PSA provides for the recovery of fuel and purchased power costs from January 1, 2007 onward.

The old PSA used historical, experienced costs to set a PSA rate, and then reconciled subsequent collections thereunder to actual costs, subject to a number of guidelines and limitations. By contrast, the PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs to set a rate that is then reconciled to actual costs experienced. This PSA also provides for a transition method for the refund or collection of balances accrued under the old PSA, prior to its replacement by this PSA. This PSA also provides a mechanism for mid-year rate adjustment in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

This POA describes the application of the PSA. It assumes that the old PSA continues to apply until the Commission decision regarding the adoption of this PSA during the first quarter of 2007.

2. PSA Components

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred fuel and purchased power costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year (each February 1 through January 31 period shall constitute a PSA Year) fuel and purchased power costs and those embedded in base rates.

2. The Historical Component, which tracks the differences between the PSA Year's actual fuel and purchased power costs and those recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PSA Year.
3. The Transition Component, which provides for:
    a. The refund or recovery of balances arising under the provisions of the old PSA, prior to its replacement by this PSA.
    b. The opportunity to seek a mid-year change in the PSA rate in cases where variances between recovery of fuel and purchased power costs under the combination of base rates and the Forward Component become so large as to warrant recovery, should the Commission first deem such an adjustment to be appropriate.
    c. The tracking of balances resulting from the application of the Transition Components, in order to provide a basis for the refund or recovery of any such balances.

The PSA Year begins on February 1 and ends on the ensuing January 31.[1] The first PSA Year in which the new PSA rate shall apply will begin on February 1, 2007 or such other date on which the Commission approves the adoption of this PSA. In any event, the first PSA Year will end on January 31, 2008. Succeeding PSA Years will begin on each February 1 thereafter.

On or before September 30 of each year, APS will submit a PSA Rate filing, which shall include a proposed calculation of the three components of the PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required. APS will supplement this filing with Historical Component and Transition Component filings on or before December 31 in order to replace estimated balances with actual balances, as explained below.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) the fuel and purchased power costs embedded in base rates and (2) the forecasted fuel and purchased power costs over a PSA Year that begins on February 1 and ends on the ensuing January 31. APS will submit, on or before September 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its fuel and purchased power costs. It will also submit a forecast of kWh sales for the same calendar year, and divide the forecasted costs by the forecasted sales to produce the ¢/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base Cost of Fuel and Purchased Power from this unit rate shall be the Forward Component.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS' over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue. This account will operate on a PSA Year basis (*i.e.*; February to January), and its

[1] The Commission decision approving this PSA may come after February 1, 2007, in which case the first PSA Year will be less than 12 months.

balances will be used to administer this PSA's Historical Component, which is described immediately below.

b. Historical Component Description

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the Forward Component Tracking Account balance and the Historical Component Tracking Account balance is divided by the forecasted kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual September 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the current PSA Year). The APS filing shall use these balances to calculate a preliminary Historical Component for the coming PSA Year[2]. On or before December 31, APS will submit a supplemental filing that recalculates the preliminary Historical Component. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the September 30 filing.

The September 30 filing's use of estimated balances for September through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision prior to February 1. The December 31 updating will allow for the use of the most current balance information available prior to the time when a Commission decision is expected. In addition to the December 31 update filing, APS monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and Historical Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected Historical Component unit rate required for the next PSA Year.[3]

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical Component collections from the Historical Component balance. The Historical Component

[2] For example, the September 30, 2007 filing would include actual balances for February through August of 2007 and estimated balances for September 2007 through January 2008.

[3] This updating to replace estimated with actual information will allow for the Commission to use the latest available balance information in determining what Historical Component is appropriate to establish for the coming PSA Year.

Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

c. Transition Component Description

As of February 1, 2007, there will remain balances under the operation of the old PSA. This PSA does not make any change in the recoverability of such balances, but does apply the Transition Component as a method for recovering such balances as are already permitted for recovery under the old PSA and whose recovery the Commission may otherwise allow. The Transition Component will provide for the capturing and collection of those balances. This plan contemplates that pre-2007 balances already approved for recovery (but not already recovered) under the old PSA will be rolled into the Transition Component upon this PSA's effective date. The Commission may, however, choose to continue recovery of any approved 2005 and 2006 balances through a continuation of the old PSA, to the extent that the new PSA may not be approved at or near February 1, 2007, or to the extent that rate elements designed to recover such balances have been set for recovery periods that do not match a PSA Year. APS will continue to make the filings required under the old PSA for so long as is necessary to recover and reconcile any balances arising thereunder, to the extent that such balances have not been transferred for recovery through the Transition Component of this PSA. In either event, all collections of approved pre-2007 balances will be subject to reconciliation.

The pre-2007 charges already approved for recovery under the old PSA consist of the following:[4]

1. February 1, 2006 adjustor rate of $0.004 per kWh, which is expected to recover about $110 million of 2005 costs through January 31, 2007, after which it is expected to be replaced by an adjustor rate that will recover expected 2006 balances
2. May 1, 2006, surcharge of $0.000554 per kWh to recover $15 million of 2005 costs outside of 4 mil bandwidth that are not related to nuclear plant outages; and expected to be collected across a duration of 12 months
3. May 1, 2006, interim adjustor rate of $0.007 per kWh to recover certain 2006 costs as described in Decision No. 68685.

Any 2007 balances accruing under the old PSA before its replacement will be tracked during the first PSA Year, and their recovery shall be addressed in the calculation of the Transition Component applicable during the second PSA Year, which shall begin on February 1, 2008, except as follows. A Commission December 2006 decision extended the interim adjustor rate of $0.007 per kWh until new rates become effective following the order in the pending rate case docket. That recent Commission decision provides for the recovery of expected 2007 costs in excess of current base rates. It appears that this extension of the $0.007 per kWh interim adjustor rate may produce a negative balance (*i.e.*, an over collection of 2007 costs) by mid-year 2007. Therefore, if the Commission decides to use the new PSA's Transition Component in the first PSA year (ending January 31, 2008) to provide for the recovery of 2005 and 2006 balances, nothing in this plan shall preclude a determination by the Commission to include any 2007

[4] Depending upon the Commission's resolution of APS' pending rate case, Docket No. E-01345A-05-0816, APS may also be allowed to recover certain prudently incurred fuel and purchased power costs incurred as a result of certain Palo Verde outages.

balances accruing under this extended $0.007 per kWh interim adjustor rate in the calculation of the Transition Component to be effective in the PSA Year ending January 31, 2008.

In order to facilitate the orderly transition to a new PSA, APS should file by December 31, 2006[5] a calculation of the ¢/kWh unit rate required to collect costs included in the preceding list over the same estimate of 2007 sales used to calculate the Forward Component. This calculation shall comprise the Transition Component for the first PSA Year's PSA rate, should the Commission determine to allow their recovery through the new PSA. APS should also file by December 31, 2006 a calculation of the ¢/kWh unit rate(s) and duration(s) required to collect costs included in the preceding list by continuing the old PSA for the purpose of their collection. Should the Commission adopt the approach of continuing the old PSA for the limited purpose of collecting any 2005 or 2006 balances, the Transition Component shall be used to reconcile all affected balances, beginning with the First PSA Year following the termination of the duration established for the collection of any remaining 2005 and 2006 balance through continuation of the old PSA.

The Transition Component will also be used if necessary to address the need for any other reconciliations that may be required or appropriate under the old PSA. Following review, the Commission will determine the amount to be collected and the period over which it will be collected. The amount permitted to be collected shall be included in the Transition Component Balance. The Transition Component will provide the PSA element for the collection of the approved Transition Component Balance over the time period established by the Commission.

The preceding uses of the Transition Component deal with the transition from the old PSA to this PSA. The Transition Component will also be used as the method for incorporating any future, approved mid-year changes to the PSA rate. APS, Staff, or the Commission on its own motion retain the ability to request at any time a change in the PSA rate through an adjustment to the Transition Component to address a significant imbalance between collections and costs under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate (¢/kWh) imposed as part of the Transition Component.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

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[5] Staff acknowledges that the 2006 information would have to be addressed in the context of the pending rate case, Docket No. E-01345A-05-0816.

As it must do for the Historical Component filing, APS shall file on or before September 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year. On or before December 31, APS will submit a supplemental filing to update the Transition Component calculation in the same manner as required for the Historical Component.

3. Calculation of the PSA Rate

The PSA rate is the sum of the three components; *i.e.*, Forward Component, Historical Component, and Transition Component. The PSA rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PSA rate by February 1, the proposed PSA rate (as amended by the updated December 31 filing) shall go into effect. The PSA rate shall be applicable to APS' retail electric rate schedules (with the exception of Solar-1, Solar-2, SP-1, E-3, E-4, E-36, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes.

The PSA rate shall be reset on February 1 of each year, and shall be effective with the first billing cycle in February unless suspended by the Commission. It is not prorated.

4. Filing and Procedural Deadlines

a. September 30 Filing

APS shall file the PSA rate with all Component calculations for the PSA year beginning on the next February 1, including all supporting data, with the Commission on or before September 30 of each year. That calculation shall use a forecast of kWh sales and of fuel and purchased power costs for the coming calendar year, with all inputs and assumptions being current as of that date for the Forward Component. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same forecast of sales used for the Forward Component calculation. The Transition Component filing shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[6]

b. December 31 Filing

APS shall by December 31 update the September 30 filing. This update shall replace estimated Forward Component Tracking Account balances, the Historical Component Tracking Account balances, and the Transition Component Tracking Account balances with actual balances and with more current estimates for those months (December and January) for which actual data are

[6] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

not available. Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect on February 1.[7]

c. Additional Filings

APS shall also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PSA.

d. Review Process

The Commission Staff and interested parties shall have an opportunity to review the September 30 and December 31 forecast, balances, and supporting data on which the calculations of the three PSA components have been based. Any objections to the September 30 calculations shall be filed within 45 days of the APS filing. Any objections to the December 31 calculations shall be filed within 15 days of the APS filing.

5. Verification and Audit

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

6. Definitions

Applicable Interest – Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15.

Base Cost of Fuel and Purchased Power – An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base Cost of Fuel and Purchased Power revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $0.0XXXXX per kWh effective on XXX, XXXX.

Forward Component – An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February. The Forward Component for the PSA Year will adjust for the difference between the forecasted fuel and purchased power costs generally expressed as a rate per kWh less the Base Cost of Fuel and Purchased Power generally expressed as a rate per kWh embedded in APS' base rates. The result of this calculation will equal the Forward Component, generally expressed as a rate per kWh.

[7] No reference in this plan to effectiveness in the absence of Commission action shall be interpreted as precluding the normal application of the balance reconciliation provisions generally established for the new PSA.

Forward Component Tracking Account – An account that records on a monthly basis APS' over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component – An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account – An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest; the balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI –Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mark-to-Market Accounting – Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load – Native load includes customer load in the APS control area for which APS has a generation service obligation and PacifiCorp Supplemental Sales.

PacifiCorp Supplemental Sales – The PacifiCorp Supplemental Sales agreement is a long-term contract from 1990, which requires APS to offer a certain amount of energy to PacifiCorp each year. It is a component of the set of agreements that led to the sale of Cholla Unit 4 to PacifiCorp and the establishment of the seasonal diversity exchange with PacifiCorp.

Old PSA – The Power Supply Adjustment mechanism approved in Decision No. 67744 to track changes in the APS cost of obtaining fuel and purchased power.

This PSA – The Power Supply Adjustment mechanism approved by the Commission in Decision No. xxxxx, which is a combination of three rate components that track changes in the cost of obtaining power supplies based upon forward-looking estimates of fuel and purchased power costs that are eventually reconciled to actual costs experienced. This PSA also provides for the transition from the prior PSA to this PSA, allows for special Commission consideration of extreme volatility in costs or recovery by means of a mid-year rate correction, and provides for a reconciliation between actual and estimated costs of the last two months of estimated costs used in Historical Component calculations.

PSA Year – A consecutive 12-month period generally beginning each February 1.

PSA Year One – A period beginning on the date determined by the Commission in Decision No. xxxxx and ending on January 31, 2008.

Preference Power – Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

System Book Fuel and Purchased Power Costs – The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs are included; broker fees are excluded.

System Book Off-System Sales Revenue – The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale – The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component – An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for: (a) the transition between the prior PSA and current PSA, and (b) significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account – An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) – Amounts payable to others for the transmission of APS' electricity over transmission facilities owned by others.

7. Calculations

a. Schedule 1. PSA Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PSA columns and then complete the following in each respective column:

1. On Line 1, enter the Forward Component Rate from Schedule 2, Line 8.
2. On Line 2, enter the Historical Component Rate from Schedule 4, Line 5.
3. On Line 4, enter the Transition Component Rate for the Commission approved prior PSA transition refund/collection balance from Schedule 6, Line 3.
4. On Line 5, enter the Transition Component Rate for any Commission approved Mid-Period Transition refund/collection balance from Schedule 6, Line 6.

5. On Line 6, enter the Transition Component Rate for any other Commission approved Transition adjustment refund/collection balance from Schedule 6, line 9.
6. On Line 7, enter the Tracking Account Transition Component Rate for any Commission approved refund/collection Tracking Account balance from Schedule 6, Line 20.
7. On Line 8, enter the sum of Lines 4 through 7 to calculate total Transition Component Rate.
8. On Line 9, enter the sum of Lines 1, 2, and 8 to calculate the total PSA Rate.
9. Calculate the Increase/(Decrease) in rates and % Change by respective lines: Proposed Rates Less Current Rates equals Increase/(Decrease) with result divided by Current Rate to determine % of Increase/(Decrease).

Reflect notes as appropriate.

b. Schedule 2. PSA Forward Component Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PSA columns and then complete the following in each respective column:

1. On line 1, enter the Projected Fuel and Purchased Power Costs for the coming year.
2. On Line 2, enter the Projected Off-System Sales Revenue (entered as a negative value) for the coming year.
3. On Line 3, enter the PSA Adjustments to Fuel and Purchased Power Costs for the coming year.
4. On Line 4, enter the sum of Lines 1 through 3 to arrive at the Net Fuel and Purchased Power Costs.
5. On Line 5, enter the Projected Native Load Sales (MWh), excluding the E-3, E-4, E-36 sales for the coming year.
6. On Line 6, enter the derivation of the Net Fuel and Purchased Power Costs divided by the Projected Native Load Sales to arrive at the Projected Average Net Fuel Cost per kWh.
7. On Line 7, enter the Authorized Base Cost of Fuel and Purchased Power Rate per kWh.
8. On Line 8, enter the sum of Line 6 less Line 7 to arrive at the Forward Component rate per kWh; and then carry forward resultant value to Schedule 1, Line 1.

Reflect notes as appropriate.

c. Schedule 3. Forward Component Tracking Account

Enter the appropriate: effective dates for the PSA ***Prior*** Forward Component being tracked; year for the column headed "Cycle Billing Month"; and Base Rate and Forward Component in columns ***h*** and ***i***. On lines 1 through 12 under the Cycle Billing Month, January through December for each respective column complete the following:

1. On Lines 1 to 12, enter the monthly PSA Retail Energy Sales (MWh) and the monthly Wholesale Native Load Energy Sales in columns ***a*** and ***b***, respectively; the sum which equals the Total Native Load Energy Sales; column ***c***. Currently, Wholesale Native Load Energy Sales include Traditional Sales-for-Resale and PacifiCorp Supplemental Sales.

2. On Lines 1 to 12, enter the monthly System Book Fuel and Purchased Power Costs and the monthly System Book Off-System Sales Revenue in columns ***d*** and ***e***, respectively; the sum of column ***d*** minus ***e*** equals the monthly Net Native Load Power Supply Costs in column ***f***. The off-system sales margin is embedded in the Net Native Load Power Supply Cost. The costs associated with the off-system sales are included in the System Book Fuel and Purchased Power Costs. When the System Book Off-System Sales Revenue is subtracted from the System Book Fuel and Purchased Power Costs, the difference between the off-system sales costs and revenue ends up in the Net Native Load Power Supply Cost. That difference is the off-system sales margin. A list of the items included in the PSA sales and costs described above will be included in the PSA reporting schedules filed with the Commission each month.
3. On Lines 1 to 12, calculate the PSA Retail Power Supply Costs, column ***g*** by dividing the PSA Retail Energy Sales in column ***a*** by the Total Native Load Energy Sales in column ***c***, then multiply the product by the Net Native Load Power Supply Costs in column ***f***. Directly-assigned power supply costs and related energy sales from applicable special contract customers, Schedule E-36 customers, and customers returning to Standard Offer service from competitive generation subject to Returning Customer Direct Access Charge ("RCDAC") treatment will be deducted prior to the above calculations.
4. On Lines 1 to 12, calculate the amount recovered via the Commission approved embedded base fuel and purchased power rate by multiplying the Retail Energy Sales in column ***a*** by the Commission approved Base Cost of Fuel and Purchased Power rate entered in the above column heading the result which is entered in column ***h***.
5. On Lines 1 to 12, calculate the amount recovered via the Forward Component rate by multiplying said rate by the Retail Energy Sales in column ***a***, the result which is entered in column ***i***.
6. On lines 1 to 12, calculate the respective level of (Over)/Under Collection in column ***j*** by subtracting the Base Rate Power Supply Recovery and the Forward Component Recovery from the PSA Retail Power Supply Costs, columns ***g*** and ***h***, respectively.

An interest rate, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, is applied each month to the previous month's Tracking Account Balance. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

The (Over)/Under Collection, the Interest and the prior month's Tracking Account Balance produce the current month's balance.

d. Schedule 4. PSA Historical Component Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PSA-2 columns and then complete the following in each respective column:

1. On Line 1, enter the Forward Component Tracking Account Balance from Schedule 3, L13, column ***i***.

2. On Line 2, enter the Historical Component Tracking Account Balance from Schedule 5, Line 8.
3. On Line 3, enter the sum of Lines 1, and 2 to arrive at the Total (Refundable)/Collection Amount Balance.
4. On Line 4, enter the respective Projected Energy Sales without E-3, E-4 and E-36 MWh.
5. On Line 5, enter the Applicable Historical Component rate by dividing Line 3 by Line 4.

Reflect notes as appropriate.

e. Schedule 5. Historical Component Tracking Account

Enter the appropriate: effective dates for the PSA ***Prior*** Historical Component being tracked.

On Line 8, for January and Line 1 for February, enter the Historical Component balance as of February 1, 20XX. On Line 2, (Prior period PSA Historical Component Calculation From Schedule 4, L4) for February enter any true-up for the use of prior period estimates, i.e., prior estimated December and January Historical Component rate application revenues to subsequent actual data, the sum of Lines 1 and 2, to reflect the Adjusted Historical Component Beginning Balance as of February 1, 20XX.

Each month, the Applicable Historical Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable Historical Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Reflect notes as appropriate.

f. Schedule 6. PSA Transition Component Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PSA columns and then complete the following in each respective column:

1. On Line 1, enter the Prior PSA Transition Commission Approved (Refundable)/Collection Amount.
2. On Line 2, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
3. On Line 3, calculate the Prior PSA Transition Component (Refundable)/Collection Rate by dividing Line 1 by Line 2.
4. On Line 4, enter the PSA Mid-Period Transition Commission Approved (Refundable)/Collection Amount, if any.
5. On Line 5, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
6. On Line 6, calculate the Mid-Period Transition Component (Refundable)/Collection Rate by dividing Line 4 by Line 5.

7. On Line 7, enter Any Other Transition Commission Approved (Refundable)/Collection Amount, if any.
8. On Line 8, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
9. On Line 9, calculate the Any Other Transition Component (Refundable)/Collection Rate by dividing Line 7 by Line 8.
10. On Line 10, enter the sum of Lines 3, 6, and 9 to arrive at the total Transition Component Rate (Non-Tracking Account Items).
11. On Line 11, enter the Prior PSA Transition Tracking Account Balance from Schedule 7a, Line 8.
12. On Line 12, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
13. On Line 13, calculate the Prior PSA Tracking Account Transition Component (Refundable)/Collection Rate by dividing Line 11 by Line 12.
14. On Line 14, enter the Mid-Period PSA Transition Tracking Account Balance from Schedule 7b, Line 8, if any.
15. On Line 15, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
16. On Line 16, calculate the Mid-Period Tracking Account Transition Component (Refundable)/Collection Rate by dividing Line 14 by Line 15.
17. On Line 17, enter Any Other PSA Transition Tracking Account Balance from Schedule 7X, Line 8, if any.
18. On Line 18, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
19. On Line 19, calculate the Any Other Tracking Account Transition Component (Refundable)/Collection Rate by dividing Line 17 by Line 18.
20. On Line 20, calculate the total Tracking Account Transition Component by adding Lines 13, 16, and 19.
21. On Line 21, calculate the total Transition Component Rate by adding Lines 10 and 20.

Reflect notes as appropriate.

g. Schedule 7a. Transition Component Tracking Account "Old PSA"

Enter the appropriate: effective dates for the PSA ***Prior*** Transition Component to be tracked.

On Line 8, for January and Line 1 for February, enter the Transition Component, Old PSA balance as of February 1, 20XX. On Line 2, (Prior period PSA Transition Component Calculation From Schedule 6, L1) for February enter any true-up for the use of prior period estimates, i.e., prior estimated December and January Transition Component, Old PSA application revenues to subsequent actual data, the sum of Lines 1 and 2, to reflect the Transition Component Adjusted Beginning Balance as of February 1, 20XX.

Each month, the Applicable Transition Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable Transition Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor

publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Any subsequent balance produced must be approved by the Commission for later inclusion in the next Transition Component Calculation, if any, at Schedule 6, Line 11.

Reflect notes as appropriate.

h. Schedule 7b. Mid-Period Transition Tracking Account

Enter the appropriate: effective dates for the PSA ***Mid-Period*** Transition Component to be tracked.

On Line 8, for January and Line 1 for February, enter the Transition Component, PSA Mid-Period balance as of February 1, 20XX. On Line 2, (Prior period PSA Transition Component Calculation From Schedule 6, L4) for February enter any true-up for the use of prior period estimates, i.e., prior estimated December and January Transition Component rate application revenues to subsequent actual data, the sum of Lines 1 and 2, to reflect the Adjusted Transition Component Beginning Balance as of February 1, 20XX.

Each month, the Applicable Transition Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable Transition Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Any subsequent balance produced must be approved by the Commission for later inclusion in the next Transition Component Calculation, if any, at Schedule 6, Line 14.

Reflect notes as appropriate.

i. Schedule 7X. (Enter Description) Transition Tracking Account

Follow similar procedures discussed in g and h above, for any other Transition Tracking Accounts.

8. Compliance Reports

APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of

his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component, and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs.
    b. Customer sales in both MWh and thousands of dollars by customer class.
    c. Number of customers by customer class.
    d. A detailed listing of all items excluded from the PSA calculations.
    e. A detailed listing of any adjustments to the adjustor reports.
    f. Total off-system sales revenues.
    g. System losses in MW and MWh.
    h. Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:
    1. Net generation, in MWh per month, and 12 months cumulatively.
    2. Average heat rate, both monthly and 12-month average.
    3. Equivalent forced-outage rate, both monthly and 12-month average.
    4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
    5. Total fuel costs per month.
    6. The fuel cost per kWh per month.

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):
    1. The quantity purchased in MWh.
    2. The demand purchased in MW to the extent specified in the contract.
    3. The total cost for demand to the extent specified in the contract.
    4. The total cost of energy.

C. Information on off-system sales shall include the following items:
    1. An itemization of off-system sales margins per buyer.
    2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:

1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

E. APS will also provide:
1. Monthly projections for the next 12-month period showing estimated (Over)/under-collected amounts.
2. A summary of unplanned outage costs by resource type.
3. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
4. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund, if those costs are found to be imprudently incurred.

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

b. Directly Assignable Power Supply Costs Excluded

Decision No. 66567 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component

of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs are excluded from the PSA.

Attachment RCS-5

Copies of UNS Electric's Responses to Data Requests

Referenced in the Direct Testimony and Schedules of

Ralph C. Smith

Data Request No.	Subject	Confidential	Pages
STF 3.87	Fair Value Rate Base	No	2-3
STF 15.4	Adjust CWIP for Plant in Service by End of Test Year and Customer Advances	No	4-11
STF 3.60	Accumulated Deferred Income Taxes	Yes	12-18
STF 11.24	Fleet Fuel Expense	No	19-21
STF 3.101	Injuries & Damages Expense	No	22
STF 11.16	Worker's Compensation Expense	No	23
STF 3.102	Injuries & Damages Expense	No	24
STF 11.15	Injuries & Damages Expense	No	25-28
STF 3.83	Incentive Compensation and SERP Expense	Yes [1]	29-49
STF 11.5	Incentive Compensation Expense (Issued in UNS Gas - Docket No. G-04204A-06-0483	No	50-51
STF 10.11	Stock Based Compensation	No	52-53
STF 3.72	EEI and Other Membership Dues	No	54-56
MM DR 2.27	Other Membership Dues	No	57
STF 3.55	Other Membership Dues	No	58-60
STF 3.39 & STF 11.8	Depreciation Expense	No	61-72
STF 3.70, STF 10.4, STF 10.5, STF 10.6, STF 11.10 and STF 15.1	SES Affiliated Charges	No	73-79
STF 3.19 & STF 3.30	Depreciation Rates	No	80-81
STF 11.2	Black Mountain Generating Station	No	82
	Total Pages Including this Page		82

[1] Only the attachments to the response for subparts d, e and f on pages 35-49 are confidential.

Pages 12-18 and 35-49 containing information designated as "Confidential" by the Company have been redacted from Attachment RCS-5 and have been filed under seal in a separate document.

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007**

STF 3.87 Fair value rate base.

a. As of August 11, 2003, the date of acquisition, would the fair value of the assets acquired from Citizens be equal to the purchase price paid by UniSource? If not, explain fully why not.

b. Was the acquisition of the electric utility the result of an arm's length transaction between a willing and informed buyer and a willing and informed seller? If not, explain fully why not.

c. In deciding how much to pay for the electric utility, please describe how and to what extent UniSource make use of reconstructed cost new (RCN) information, reconstructed cost new depreciated (RCND) information, Handy-Whitman Index information, Marshall Index information, and/or Bureau of Labor Statistics index information. To the extent that UniSource did not use such information as the basis for determining the purchase price to pay for the electric utility, please explain fully why not.

d. Why does UniSource believe it was able to acquire the electric utility at a price less than original cost depreciated book value? Explain fully.

RESPONSE:

a. Yes.

b. Yes.

c. The above-referenced information was given little or no weight in deciding what price UniSource Energy would be willing to pay for the electric utility properties owned by Citizens. Instead, the purchase price was more heavily influenced by the physical condition of the utility properties, the ability to recover purchased power costs, prevailing rates for distribution services, financing costs, and the expected growth in sales, expenses and capital expenditures.

d. There are two primary reasons. First, the retail rates charged for distribution services provided an inadequate rate of return on the original cost depreciated book value of utility property. Second, Citizens appeared to be a highly motivated seller, as witnessed by its decision to write-off a substantial balance of deferred purchased power costs.

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007

RESPONDENT: Kent Grant

WITNESS: Kent Grant

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S FIFTEENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 26, 2007

STF 15.4 Customer Advances. Please refer to the response to STF 10.20.

a. Are the $12,045,607 Customer Advances as of June 2006 in FERC Account 252 reflected anywhere on Schedule B-1, Summary of Original Cost and RCND Rate Base? If so, where are the Customer Advances reflected on that schedule and in what amount.

b. Are the $12,045,607 Customer Advances as of June 2006 in FERC Account 252 reflected anywhere on Schedule B-2, Pro Forma Adjustments to Original Cost Rate Base? If so, where are the Customer Advances reflected on that schedule and in what amount.

c. Has UNS Electric included any amounts of Accumulated Deferred Income Taxes (ADIT) in rate base related to the amount Customer Advances as of June 2006? If so, please identify all ADIT amounts in rate base related to Customer Advances, and clearly show the relationship between the amount of Customer Advances that the Company has reflected as a deduction to rate base and the amount of ADIT that the Company has included in rate base related to Customer Advances.

d. As of 6/30/06, had UNS Electric received any Customer Advance relating to the Tubac Golf Resort Overhead to Underground Conversion (Task CE64023)? If so, please identify the Customer Advance related to this project that was recorded on UNS Electric's books as of 6/30/06.

e. Subsequent to 6/30/06, has UNS Electric received any Customer Advance relating to the Tubac Golf Resort Overhead to Underground Conversion (Task CE64023)? If so, please identify the amount of Customer Advances related to this project that was recorded on UNS Electric's books subsequent to 6/30/06.

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S FIFTEENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 26, 2007**

f. As of 6/30/06, had UNS Electric received any Customer Advance relating to the Rhodes Homes line extension project (Task 8009729)? If so, please identify the Customer Advance related to this project that was recorded on UNS Electric's books as of 6/30/06.

g. Subsequent to 6/30/06, has UNS Electric received any Customer Advance relating to the relating to the Rhodes Homes line extension project (Task 8009729)? If so, please identify the amount of Customer Advances related to this project that was recorded on UNS Electric's books subsequent to 6/30/06.

h. Please show in detail how the amounts of Customer Advances listed in response to c, d, e and f were determined.

i. Subsequent to 6/30/06, has UNS Electric refunded any Customer Advances relating to the Rhodes Homes line extension project (Task 8009729) or to the Tubac Golf Resort Overhead to Underground Conversion (Task CE64023)? If so, please identify the date and refund amounts for any and all refunds related to each project.

RESPONSE:

a. STF 10.20 a. has been revised. The revised table reflects a June 30, 2006 Customer Advance balance of $8,692,444. This is the balance that is reflected on Schedule B-1, Summary of Original Cost and RCND Rate Base.

b. STF 10.20 a. has been revised. The revised table reflects a June 30, 2006 Customer Advance balance of $8,692,444. This is the balance that is reflected on Schedule B-2, Pro Forma Adjustments to Original Cost Rate Base.

c. Consistent with Commission Decision No. 55774, issued in October 1987, the rate base element Accumulated Deferred Income Taxes includes the Deferred Tax Asset associated with Contributions and Advances in Aid of Construction, computed at the average test year amount. For a detailed itemization of Accumulated Deferred Income Taxes, please refer to the response to STF 3.60.

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S FIFTEENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 26, 2007

d. No. This customer requested work was paid 100% by the customer as a Contribution in Aid of Construction.

e. Please see the response to d. above.

f. Yes. As of June 30, 2006 UNS Electric had received $360,117.09 for this project.

g. No.

h. For subpart c. above, ADIT for customer advances is computed by taking the average of the total post acquisition advance liabilities as of June 30, 2005 and June 30, 2006. Pre Acquisition advances have no impact on ADIT. Please see STF 15.4 (h) (Cust. Adv. ADIT), Bates No. UNSE(0783)09893, on the enclosed CD for the calculation of subpart c.

Subparts (d) and (e) are not applicable.

Please see 15.4 (h) (Line Ext. Cost Est.), Bates No. UNSE(0783)09894, on the enclosed CD for the detailed Line Extension Cost Estimate, a letter requesting an engineering advance and the Letter of Agreement to Rhodes Homes.

i. No refunds have been made to Rhodes Homes (Task 8009729). Tubac Golf Resort (Task CE 64023) would not be eligible for a refund.

RESPONDENTS: Sandie Becker (a and b)
Carl Dabelstein (c)
Tom Hoyt (d and e)
Teri Rice (f, g, h and i)

WITNESSES: Karen Kissinger (a, b and c)
Thomas Ferry (d, e, f, g, h and i)

LINE EXTENSION COST ESTIMATE

MOHAVE ELECTRIC - KINGMAN, ARIZONA

Customer Rhodes Homes AZ/GV Well #1
8009729

Prepared By GKELLER
Date 03/02/06

PHASE	CONSTRUCTION UNIT	UNIT COST	# REQD.	EXTENDED
	TANGENT			0.00
	ANGLE			0.00
	DEAD END			0.00
	DOUBLE DEAD END			0.00
	SLACK SPAN			0.00
	INSET			0.00
	SLEEVE THROUGH/TAKE-OFF			0.00
	DOWN GUY			0.00
	OVERHEAD GUY			0.00
	ANCHOR			0.00
	LINE EXT WELL #2	34868	1	34868.00
	LINE DAMPNERS	23.88	360	8596.80
	OTHER	175,160.87	1	175160.87

LABOR

(ADDITIONAL FOREMAN/JOURNEYMAN)

Line Crew	$171.03	per hr. x	300.00	hrs.	=	$51,309.00
Digger Crew	$35.80	per hr. x	100.00	hrs.	=	$3,580.00

Total Material	$218,625.67
Total labor	+ $54,889.00
Total Direct (Material & Labor)	$273,514.67

Overhead	50.800% x labor		$27,883.61
Engineering	2.000% x (T.D. +O.H.)		$6,027.97
Interest	0.310% x .5 x (T.D. + ENG. + O.H.	3 Mos.	$1,906.04
AR-13	0.240% x (T.D. + ENG. +O.H. + IN	3 Mos.	$1,484.79
Outside Engineering/Staking Fees: (Stanley Consultants)			$49,300.00
Total Cost			$360,117.09

STF 15.4 (h.f)

2308 Airway Avenue
P.O. Box 3099
Kingman, Arizona 86402-3099
928 681-8100

UniSource
SERVICES

November 29, 2005

Mr. Kirk Brynjulson
Mr. James Rhodes
Rhodes Homes Arizona
2215 Hualapai Mountain Road, Suite H
Kingman, Arizona 86401

RE: Electric Service - Preparation Cost
4621 West Dora Drive, Golden Valley Well #1

Dear Sirs:

This letter is in reference to your inquiry regarding the cost of extending three-phase overhead electric distribution lines to 4621 West Dora Drive, Parcel 306-63-009, situate in Section 34, Township 21 North, Range 18 West, Gila and Salt River Meridian, Mohave County, Arizona.

UNS Electric, Inc. would need to construct a three-phase overhead distribution line approximately 23,760 feet to reach your service area. A rough estimate of the construction cost is determined to be approximately $300,000.00. You will be required to advance the total cost of construction prior to the start of construction of the electric facilities.

If you request a detailed plan and cost estimate, you will be required to deposit with UNS Electric, Inc. an amount of $30,000.00 to cover the estimated cost of preparation. If you authorize UNS Electric, Inc. to proceed with construction of the extension within twelve months after receiving the extension agreements, the deposit shall be credited to the cost of construction; otherwise, the deposit shall be non-refundable.

If the proposed route will require UNS Electric, Inc. to obtain a right of way through BLM Land/State of Arizona Trust Land, prior experience indicates that it could take several months to acquire this permit.

Electric service will be provided in accordance with UNS Electric, Inc.'s Rules and Regulations on file with, and approved by, the Arizona Corporation Commission.

If you are in agreement to the above, please remit to UNS Electric, Inc. the amount of $30,000.00. Please feel free to contact the engineering department at 928-681-8929 if you have any additional questions.

Sincerely,

Gene M. Keller

Gene M. Keller
Engineering Technician III

2498 Airway Avenue
P.O. Box 3099
Kingman, Arizona 86402-3099
928.681.4100

iiSource
SERVICES

March 2, 2006

Mr. Kirk Brynjulson
Mr. James Rhodes
Rhodes Homes Arizona
2215 Hualapai Mountain Road, Suite H
Kingman, AZ 86401

Dear Messrs. Brynjulson and Rhodes:

This Letter of Agreement is entered into between UNS Electric, Inc., an Arizona Corporation, hereinafter referred to as "Company", and Rhodes Homes Arizona, hereinafter referred to as "Customer". This Letter of Agreement covers the conditions under which Company will extend overhead electric service to 4621 West Dora Drive, Parcel 1A, Section 34, and to 1509 South Amado Road, Lot 105, Section 37, both in Township 21 North, Range 18 West, Gila and Salt River Meridian, Mohave County, Arizona. This extension will be made under the provisions of Company's Extension Rules, Section II, D.1.c. and D.3., enclosed.

Company will install 25,892 feet of three-phase 20.8-kV overhead primary distribution line and provide 2400-volt electric service to Customer's water wells.

The estimated construction cost of primary distribution facilities is $360,117.09. The extension will be made under the provisions of Section II, D.3., Economic Feasibility Basis. Therefore, upon signing this Letter of Agreement, Customer will pay to Company $280,817.09 ($360,117.09 total Customer advance less $79,300.00 payment received as a preliminary engineering advance).

Customer's advance of $360,117.09 is refundable, without interest, under the provision of Section II, D.1.c. Company will determine the refund based on actual annual revenues received from service to the two wells. An analysis will be conducted annually in accordance with Section II, D.1.c. The obligation of Company to make refunds to Customer shall terminate five (5) years after the date of this Letter of Agreement. Any refund will be made to Rhodes Homes Arizona.

Customer will furnish, or cause to be furnished, at no cost to Company, easements perpetual in nature necessary to meet service requirements. Any annual expenses associated with said easements shall be paid in advance by Customer for the term of this Letter of Agreement.

Enclosed with this Letter of Agreement is the current electric rate schedule for the type of service for which you will be billed.

Mr. Kirk Brynjulson
Mr. James Rhodes
March 2, 2006
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Company's estimated starting date for construction will commence within 30 days of execution of the Letter of Agreement and receipt of all necessary permits and easements.

This Letter of Agreement supersedes any and all other agreements or Letter of Understanding that may have come before Company in connection with the matters herein contained. Any amendment, to be effective, must be made in writing.

UNS ELECTRIC, INC.

By: Bill De Julio 3/16/06
Bill De Julio

Its: Transmission and Distribution Manager

ACCEPTED

By: _____

Date: _____

BD:gk 8009729
Enclosures: Extension Rule, Section II, D.1.c. and D. 3.
Rate Schedule

UNS Electric, Inc.
Customer Advances ADIT
Test Year Ended 6/30/2006

UNS Electric, Inc. Customer Advances Company: 033 Number, Period Name: JUN-05, JUN-06, Currency Code: USD, Natural Account: 28300, A$Acct$UNS_GL_SubAccount Parameter 1: 4040, 4041, 4043, 4044

A$Acct$UI Acct$UNS_GL_Account:28300

Period	Suba/c Description	Ending Balance	Activity	
DEC-03	Cust Adv Construct-Post Acquisition*	(509,306)	(509,306)	**B**
DEC-04	Cust Adv Construct-Post Acquisition*	(1,696,002)	(1,186,696)	**C**
JUN-05	Cust Adv Construct-Post Acquisition	(3,264,012)	(1,568,010)	**D**
DEC-05	Cust Adv Construct-Post Acquisition*	(6,447,437)	(3,183,425)	**D**
JUN-06	Cust Adv Construct-Post Acquisition	(8,704,867)	(2,257,430)	**E**
			(8,704,867)	

Source> G/L Discoverer Query

Average Balance (6/30/2005 & 6/30/2006)	(5,984,440)	
Combined Federal & State Rate	38.60%	
Total Deferred Tax Asset	**2,309,874**	A

*These amounts are not considered in computing the average advance balance. It is presented here for the computations @ F1-F2.

THE COMPANY'S RESPONSE AND ATTACHMENTS TO STAFF DATA REQUEST STF 3.60 CONTAIN INFORMATION DESIGNATED AS "CONFIDENTIAL" BY THE COMPANY AND HAS BEEN REDACTED FROM THIS DOCUMENT,

ATTACHMENT RCS-5. THE CONFIDENTIAL PAGES (12-18) ARE PROVIDED UNDER SEAL IN A SEPARATE DOCUMENT.

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STF 11.24 Fleet Fuel Expense.

a. Refer to the workpapers used to calculate UNSE's Fleet Fuel Expense adjustment, specifically, the workpaper indicated by Bates number UNSE(0783)02108. Please provide similar data in the format shown on the referenced workpaper for the period September 2006 to date.

b. Has the Company's fleet fuel expense in 2006 or 2007 been impacted by any refinery outages? If so, please identify, quantify and explain the refinery outages and the related impacts on fleet fuel costs.

RESPONSE: Please find below a table in a similar format for September, 2006 to date for fleet fuel expense for UNS Electric.

UNS Electric, Inc.
Fleet Fuel Expense - Invoices
September, 2006 - Current

Wright Express Invoices:

Invoice Date	Gallons	Fuel Cost	Month	Cost/Gallon
10/9/2006	7,678	$21,262.37	Sep-06	$2.77
11/7/2006	8,163	$20,690.44	Oct-06	$2.53
12/6/2006	5,878	$15,380.32	Nov-06	$2.62
1/6/2007	5,432	$14,316.33	Dec-06	$2.64
2/7/2007	6,283	$16,187.27	Jan-07	$2.58
3/7/2007	5,808	$14,937.11	Feb-07	$2.57
4/6/2007	6,503	$18,338.70	Mar-07	$2.82
5/6/2007	6,144	$18,354.94	Apr-07	$2.99
	51,891	$139,467.48		$2.69

Non Wright Express Invoices:

Kingman Gascard

10/5/2006	5,306	$14,208.66	Sep-06	$2.68
10/20/2006	4,578	$11,687.15	Sep-06	$2.55
11/5/2006	4,730	$11,880.83	Oct-06	$2.51
11/20/2006	5,079	$13,089.11	Oct-06	$2.58
12/5/2006	4,055	$10,891.93	Nov-06	$2.69
12/20/2006	6,373	$17,250.81	Nov-06	$2.71
1/5/2007	4,364	$13,746.23	Dec-06	$3.15

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UNS Electric, Inc.
Fleet Fuel Expense - Invoices
September, 2006 - Current

1/20/2007	4,951	$10,489.23	Dec-06	$2.12
2/5/2007	5,361	$13,260.98	Jan-07	$2.47
2/20/2007	6,249	$16,235.41	Jan-07	$2.60
3/5/2007	3,387	$9,181.32	Feb-07	$2.71
3/20/2007	4,148	$11,538.48	Feb-07	$2.78
4/5/2007	5,187	$14,657.28	Mar-07	$2.83
4/27/2007	4,371	$13,036.70	Mar-07	$2.98
5/5/2007	3,745	$11,460.83	Apr-07	$3.06
	71,885	$192,614.95		$2.68
Parker Oil				
2/28/2007	1,103	$2,789.54	Jan-07	$2.53
3/16/2007	974	$2,521.62	Feb-07	$2.59
3/31/2007	555	$1,445.36	Feb-07	$2.60
4/1/2007	2,064	$6,030.15	Mar-07	$2.92
4/16/2007	835	$2,565.84	Mar-07	$3.07
4/30/2007	1,051	$3,250.72	Mar-07	$3.09
5/16/2007	1,192	$3,700.57	Apr-07	$3.10
	7,775	$22,303.80		
Texmo Oil Company				
9/6/2006	430	$1,364.23	Sep-06	$3.17
9/7/2006	420	$1,330.63	Sep-06	$3.17
9/11/2006	561	$1,672.00	Sep-06	$2.98
9/12/2006	185	$566.54	Sep-06	$3.06
9/13/2006	345	$1,084.39	Sep-06	$3.14
	1,941	$6,017.79		
Total Fuel Cost	133,491	$360,404		$2.70

The table was derived by pulling invoices from the vendors and summarizing.

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b. The Company does not receive information from our fuel vendors regarding oil refinery outages and the possible impact outages may have had on fleet fuel expense.

RESPONDENT: Marian Bryant and Michael Daranyi

WITNESS: Dallas Dukes

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STF 3.101 Injuries and Damages. State the amount of injuries and damages expense for each of the last three years, and for the test year.

RESPONSE: The injuries and damages expense in FERC 925 is as follows:

January 2004 - December 2004	$352,589
January 2005 - December 2005	$356,992
July 2005 - June 2006 (Test Year)	$562,403
January 2006 - December 2006	$500,440

RESPONDENT: Janet Zaidenberg-Schrum

WITNESS: Dallas Dukes

UNS ELECTRIC, INC.'s RESPONSES TO
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STF 11.16 Insurance expense. Refer to the response to STF 3.102.

a. Explain fully why the Worker's Compensation Expense in the test year of $177,086 is so much higher than in 2004, 2005 and 2006.

b. Were any large or unusual monthly amounts recorded by UNS Electric for Worker's Compensation in the test year? If so, please identify and explain each such amount.

c. Why are the expense amounts for "Life, ST/LT Disability and ADD" negative for 2005 and for 2006? Explain fully. Please identify and explain the credit entries to these accounts that resulted in the negative expense amounts in each year.

d. Why are the expense amounts for "Life, ST/LT Disability and ADD" positive for the test year ending 6/30/06?

RESPONSE: a. UNS Electric is self-funded for worker's compensation claims up to $500k per claim. Worker's compensation expense consists of several items including: claims paid, claims administration fee paid to our third party administrator, excess worker's compensation premiums, quarterly reserve adjustments, and worker's compensation allocations out to capital projects. The quarterly reserve adjustment is based upon a Standard Loss Report provided by the administrator and designed to estimate probable future payments based on current information about known claims.

Expense Description	Test Year	2004	2005	2006
Claims Paid	58,231	47,737	25,994	81,058
Claims Admin. Fee	47,012	44,875	47,012	23,506
Quarterly Reserve Adj	63,252	41,686	(19,286)	20,275
Excess WC Prem.	11,634	11,941	689	10,945
Allocations to Capital	(1,548)	(16,785)	(10,241)	(24,894)
WC Refunds	(1,496)	0	0	(17,021)
Total	177,085	129,454	44,168	93,869
Worker's compensation premium charged to TEP	12,943		12,943	
Adjusted Total	190,028		57,111	

The above table reflects higher claims and reserve adjustments in the test year compared to 2004 and 2005. This is just a timing issue of when claims come through, which then is a basis for the reserve adjustment. The worker's compensation premium for 2005

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STF 3.102 Insurance Expense. Itemize each component of insurance expense included in the test year, and provide comparative information for calendar 2004, 2005 and 2006. Indicate the accounts and amounts in which each item of insurance expense is recorded.

RESPONSE:

Description	GL Account	Test Year	2004	2005	2006
Property	56040	65,598	78,770	64,630	68,458
Medical, Dental, and Vision	70520	848,198	994,265	771,405	1,016,463
Life, ST/LT Disability and ADD	70530	4,188	13,647	(1,376)	(4,425)
Officer's & Director's	78000	120,072	22,032	88,605	130,330
General Liability	78010	203,528	169,605	180,052	202,093
Injuries and Damages	78100	(7,825)	(1,229)	0	10,164
Worker's Compensation	78040, 50250	177,086	129,454	44,169	93,870

RESPONDENT: Sandie Becker

WITNESS: Karen Kissinger

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STF 11.15 Insurance expense. Refer to the response to STF 3.102.

a. Explain fully and in detail why Officers and Directors insurance has increased from $22,032 in 2004 to $88,605 in 2005 to $130,330 in 2006.

b. Provide a complete copy of the Officers and Directors insurance policy invoices for 2004 through 2006.

c. Have there been any lawsuits filed against UNS Electric or affiliate company Officers and Directors since the acquisition of the utility operation from Citizens? If so, please identify and describe all such lawsuits.

d. Were there any changes in coverage in Officers and Directors insurance from 2004 through 2006? If so, please identify and describe all such changes in coverages.

e. Were there any changes in the allocations to UNS Electric of Officers and Directors insurance from 2004 through 2006? If so, please identify, quantify and describe all such changes.

RESPONSE:

a. The increase in Officers and Directors insurance was due to how the expenses were allocated and also due to changes in coverage. Please see STF11.15 (a, d & e) on the enclosed CD for details. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers..

b. Please see STF 11.15 (b), Bates Nos. UNSE(0783)09352 to UNSE(0783)09364, on the enclosed CD for scanned invoices.

c. There have been no lawsuits filed against UNS Electric's Officers and Directors since the acquisition of the utility operation from Citizens.

d. Please see STF 11.15 (a, d & e) on the enclosed CD. This schedule shows how the invoices in response STF 11/15 b. are allocated.

The above mentioned schedule reflects the coverage limits by policy. The basic policies have remained substantially the same over the years. Various policy endorsements have been added or removed as requested by either the insurers or the insured. The named insured is UniSource Energy Corporation, although the

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was inadvertently charged to TEP. The inconsistency in the worker's compensation allocations out to capital projects in the test year is a result of migrating to the Oracle System in June 2005. During the migration to the new system, the worker's compensation allocation rates for UNS Electric were not entered and therefore, no allocation was made to capital projects from June 2005 through May 2006.

b. No.

c. In 2005 and 2006, there were a few payments inadvertently charged to TEP and UNS Gas when they should have been charged to UNS Electric; therefore, the employee deductions exceeded the amount charged to the account. In addition, there are timing differences in the payments. Premium payments to vendors are debits (expense) to the accounts, while employee deductions (withholds) are credits to the accounts.

d. The expense amounts for "Life, ST/LT Disability and ADD" are positive for the test year ending 6/30/06 because the amounts paid to the vendors for the various policies exceeded the amounts withheld from the employees' paychecks. The Company would expect to see a minimal expense in the "Life, ST/LT Disability and ADD" expense account for the following reasons:

1. Life-Union: The Company pays for the basic (1 times annual salary).
2. Life-Non Union: The Company pays for 1.5 times the annual salary.
3. LTD-Union: Employee receives enough credit to pay for 50% up to 3k per month pre and post tax. They may choose to buy up to 66 2/3% at their expense.
4. LTD-Non Union: Employee receives enough credit to pay for 50% up to 3k per month pre and post tax. They may choose to buy up to 66 2/3% at their expense.
5. ADD-Non Union only: Company pays for $20,000, no cost to employee.

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6. Business Travel Accident Insurance-Non Union: Company pays for $250,000, no cost to employee.

7. Business Travel Accident Insurance-Union: Company pays for 5 times the annual salary, no cost to employee.

RESPONDENT: Sandie Becker

WITNESS: Karen Kissinger

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coverage extends to all Directors and Officers of any owned subsidiary.

e. Yes, there were changes in allocations to UNS Electric of Officers and Directors insurance from 2004 through 2006. Please see STF11.15 (a, d & e) on the enclosed CD for the changes.

RESPONDENT: Sandie Becker

WITNESS: Karen Kissinger

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STF 3.83 Employee Benefits.

a. List and describe all retirement and incentive programs available to Company officers and employees and to affiliate officers and employees whose cost is charged to UNS Electric.

b. Specifically identify the cost of any SERP or similar programs directly charged or allocated.

c. State the cost by program, of each retirement program directly charged or allocated.

d. Provide the PEP financial performance goals for 2005, 2006 and 2007.

e. For each PEP goal, for each year, show the actual results and how it compared with the target.

f. Provide the PEP in effect in each year, 2005, 2006 and 2007.

g. Show in detail how any special recognition awards recorded in the test year were determined.

h. Provide the amounts of Officer's Long-term Incentive compensation in total and charged to UNS Electric during the test year. Include supporting calculations.

SUPPLEMENTAL RESPONSE: UniSource Energy Services ("UES") is a subsidiary of UniSource Energy Coporation and the parent Company of UNS Electric.

a. Incentives

UNS Electric non-union employees participate in UES' Performance Enhancement Program ("PEP"). The structure determines eligibility for certain bonus levels by measuring UES' performance in three areas:

- financial performance,
- operational cost containment, and
- core business and customer service goals.

Levels of achievement in each area are assigned percentage-based "scores". Those scores are combined to calculate the final payout level. The amount made available for bonuses through this formula may range from 15% to 150 % of the targeted payment level.

The financial performance and operational cost containment components each make up 30% of the bonus structure, while the

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core business and customer service goals account for the remaining 40 %.

The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages as a percent of base salary range from 3% - 14% for regular non-union employees, and 25% - 80% for Managers and Officers. Bonus percentages as a percent of base salary are used in the calculation of total available dollars, and actual awards may vary at management's discretion based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year.

Retirement Programs
UNS Electric employees are eligible to participate in the UES Pension Plan. For a description of this plan, please see STF 3.82 (Final UES Pension SPD v1 6-28-2004), on the enclosed CD.[1] Additionally, UNS Electric employees are eligible to participate in the Tucson Electric Power Company ("TEP") 401(k) Plan as described below:

TEP 401(K) Plan
TEP's 401(k) Plan takes advantage of Section 401(k) of the Internal Revenue Code and permits employees to voluntarily save from 1/2% to 50% of their pay, before any deduction for state or federal income taxes. The Company matches 50 cents on the dollar, up to the first 6% of pay saved, in the 401(k) Plan for UNS Electric employees.

Employees' savings and Company matching contributions are invested in one or any combination of a selection of professionally managed investment funds at the direction of the employee. Employees are eligible to join the 401(k) Plan upon their date of employment. Company matching contributions are fully and immediately vested.

[1] This attachment is not identified by Bates numbers. UNS Electric will provide this same attachment, with Bates numbers, shortly.

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TEP Salaried Employees Retirement Plan ("Salaried Plan")
(This description is included because some cost is allocated back to UES for officer participation.)

The Salaried Plan provides an annual income based on the following formula:

1.6% *times* Final Average Pay
times
Years of Service (up to 25 years)

Final average pay is the average of basic monthly earnings, on the first of the month following the employee's birthday, during the five consecutive plan years in which basic monthly earnings were the highest, within the last 15 plan years before retirement.

Years of service are based on the employee's years and months of employment with TEP or a participating affiliated corporation. The employee is vested in his or her retirement benefit after five years of service.

The maximum benefit available under the plan is an annual income of 40% of final average pay. Plan compensation for purposes of determining final average pay is limited to IRS compensation limits (Code Section) 401(a)(17). In addition, contributions to the UniSource Energy Corporation Management and Directors Deferred Compensation Plan ("Deferred Compensation Plan") are not considered eligible compensation under the Salaried Plan.

TEP Excess Benefit Plan ("Excess Plan")
(This description is included because some cost is allocated back to UES for officer participation.)

The Excess Plan provides benefits to officers and other highly compensated employees in addition to the benefits payable under the Salaried Plan.

Compensation used to determine final average pay under the Salaried Plan is limited by annual IRS compensation limits (Code Section) 401(a)(17)), and is further reduced by any contributions to the Deferred Compensation Plan.

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The Excess Plan retirement benefit is calculated using the Salaried Plan formula without regard to the IRS limits on compensation, voluntary salary reductions to the Deferred Compensation Plan, and the annual incentive bonus is added to the earnings rate. The retirement benefit payable from the Excess Plan will be reduced by the benefit payable from the Salaried Plan.

UniSource Energy Corporation Management and Directors Deferred Compensation Plan ("Deferred Compensation Plan")

The Deferred Compensation Plan allows participants (Directors, Officers and Managers) the opportunity to accumulate tax-deferred capital by allowing them to defer a portion of their pay on a pre-tax basis.

Salary and Bonus Deferral
A participant may elect to defer a percentage of their salary or bonus up to 100%. The minimum salary deferral amount is $3,500. Pay deferred under the plan is not included in W-2 earnings. Therefore, deferrals are not subject to federal or state income taxes at the time of deferral. However, deferred pay is subject to FICA and Medicare taxes in the year of deferral.

401(k) Excess Company Match
Limits on contributions to the TEP 401(k) Plan may keep highly compensated employees from receiving the full dollar-for-dollar Company match. If employees maximize their 401(k) deferral opportunity ($15,000 in 2006), the Company will contribute an amount to the Deferred Compensation Plan equal to the additional matching contribution that they would have received under the 401(k) Plan if their compensation in excess of the legal limitation ($220,000 in 2006) had been taken into account.

Receiving Account Balance
Full account balance will be distributed following retirement or termination. In the event of insolvency, plan participants will be general, unsecured creditors of the Company.

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b. SERP Expense charged to UNS Electric during the test year was $83,506.

c. Retirement Plan Expense (other than SERP) charged to UNS Electric during the test year was as follows:

UES Pension Plan	$230,361
UES 401K Plan	$ 73,112
TEP Pension/401K	$234,796
UNS Gas Pension/401K	$ 2,190
Deferred Comp Plan	$ 9,035
Total	$549,494

d. Please see STF 3.83 (d - PEP 2005) on the enclosed CD for 2005 PEP goals. The Excel file, STF 3.83 (d – PEP 2005), is not identified by Bates numbers. Please see STF 3.83 (d – PEP 2006) and STF 3.83 (d – PEP 2007), Bates Nos. UNSE(0783)08261 to UNSE(0783)08266 , on the enclosed CD, for 2006 and 2007 PEP goals for UNS Electric. STF 3.83 (d - PEP 2005), STF 3.83 (d – PEP 2006), and STF 3.83 (d – PEP 2007) contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

e. In 2005, the primary financial goal of PEP was not met; therefore, no PEP was awarded in 2005. Please see STF 3.83 (d - PEP 2005) for 2005 results. See STF 3.83 (e - PEP 2006 Final Results), Bates Nos. UNSE(0783)08267 to UNSE(0783)08268, on the enclosed CD, for the PEP 2006 program and for the 2006 results. STF 3.83 (d - PEP 2005) and STF3.83 (e - PEP 2006 Final Results) contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

f. In 2004, UES' PEP goals were separate from those of TEP. PEP had two primary goals: a financial goal specific to UES (UNS Gas and UNS Electric combined) and a set of goals measuring UNS Electric expense management, customer service, system reliability, and safety. Each of the two primary goals was weighted equally; however, PEP only paid if the primary financial goal was met. The primary UES financial goal was met in 2004.

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May 25, 2007**

In 2005, PEP had a structure similar to 2004, with two primary goals. However, the primary financial goal was now a combined financial measure for UNS Electric, UNS Gas and TEP. The second primary goal measured UNS Electric financial performance, customer and reliability goals, integration goals, and safety and employee goals. Similar to the prior year, each of the two primary goals was weighted equally and PEP only paid if the primary financial goal was met. As stated in response STF 3.83(e) above, the 2005 primary financial goal was not met.

In 2006, the PEP structure was changed to the program that exists today. It consists of three independent primary goals, and each of the primary goals has its own trigger, meaning that if one of the primary goals is not met, there is still an opportunity to achieve the two remaining primary goals. The three primary goals are comprised of a UniSource Energy Corporation Earnings per Share goal (weighted 30%), a Cost Containment goal which manages Operations and Maintenance spending (weighted 30%), and Core Business and Customer Service goals (weighted 40%). The Core Business and Customer Service goals have many sub-goals beneath them, measuring reliability, customer service, project completion, regulatory and safety.

g. Special recognition awards were not recorded in the test year.

h. Please see STF 3.83 (h) on the enclosed CD for amounts of Officer's Long-term Incentive compensation in total and charged to UNS Electric during the test year. Supporting calculations are included in this file. STF 3.83 (h) is <u>not</u> identified by Bates numbers, contains confidential information and is being provided pursuant to the terms of the Protective Agreement.

RESPONDENT: a. Steve Bracamonte
b. c. and h. Amy Teller
d. e. f. and g. Michael Daranyi

WITNESS: a., d., e., f., g. and h. – Dallas Dukes
b., c., and h. – Karen Kissinger

ATTACHMENTS D, E AND F TO THE COMPANY'S RESPONSE TO STAFF DATA REQUEST STF 3.83 CONTAIN INFORMATION DESIGNATED AS "CONFIDENTIAL" BY THE COMPANY AND HAS BEEN REDACTED FROM THIS DOCUMENT, ATTACHMENT RCS-5. THE CONFIDENTIAL PAGES (35-49) ARE PROVIDED UNDER SEAL IN A SEPARATE DOCUMENT.

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S ELEVENTH SET OF DATA REQUES
DOCKET NO. G-04204A-06-0463
January 18, 2007

UNS GAS
Docket No.
G-04204A-06-0463

STF 11.5 Incentive Compensation. Refer to the response t

a. Show in detail the 2004 and 2005 PEP financ and the actual results.

b. Show in detail how the Special Recognition Award in 2005 was determined.

c. Provide the PEP in effect during each year, 2004, 2005 and 2006.

RESPONSE:

a. Please see STF 11.5(a), Bates Nos. UNSG(0463)05831 to UNSG(0463)05832, on the enclosed CD for the 2004 and 2005 UNS Gas, Inc. ("UNS Gas") portion of PEP which includes financial performance goals and actual results. STF 11.5(a) contains confidential information and is being provided pursuant to the terms of the Protective Agreement.

b. UNS Gas is in the process of gathering this information and will provide it shortly.

c. UNS Gas is in the process of gathering this information and will provide it shortly.

SUPPLEMENTAL RESPONSE:

a. UNS Gas' response to STF 11.5 (a) was provided to Staff on January 9, 2007.

b. As previously stated, the financial performance goal, which was a trigger under the PEP program for UNS Electric, UNS Gas and Tucson Electric Power Company ("TEP"), was not met. The financial performance was not met, in part, because of unplanned outages at the coal generating units which required TEP to purchase power on the open market. In discussions with the Board of Directors, the desire was to recognize employee achievements distinct from financial measures. The Board deemed it appropriate to implement a Special Recognition Award to employees for achievements in 2005. Normally, PEP is paid at 50% to 150% of target; the Special Recognition Award was paid at approximately 42% of the target for each of the three operating companies.

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S ELEVENTH SET OF DATA REQUESTS DOCKET NO. G-04204A-06-0463 January 18, 2007

c. In 2004, the UniSource Energy Services, Inc. ("UES") PEP goal was separate from that of TEP. It had two primary goals: a financial goal specific to UES (UNS Gas and UNS Electric combined) and a set of goals measuring UNS Gas expense management, customer service, system reliability, and safety. Each of the two primary goals was weighted equally; however, PEP only paid if the primary financial goal was met. The primary UES financial goal was met in 2004.

In 2005, PEP had a similar structure as 2004 with two primary goals. However, the primary financial goal was now a combined financial measure for UNS Electric, UNS Gas and TEP. The second primary goal measured UNS Gas financial performance, customer and reliability goals, integration goals, and safety and employee goals. Similar to the prior year, each of the two primary goals was weighted equally and PEP only paid if the primary financial goal was met. As stated in response to STF 11.5 b, the 2005 primary financial goal was not met.

In 2006, the PEP structure was changed to the existing program today. It consists of three independent primary goals, and each of the primary goals has its own trigger, meaning that if one of the primary goals is not met, there is opportunity to still achieve on the two remaining primary goals. The three primary goals are comprised of a UniSource Energy Corporation Earnings per Share goal (weighted 30%), a Cost Containment goal which manages Operations and Maintenance spending (weighted 30%), and Core Business and Customer Service goals (weighted 40%). The Core Business and Customer Service goals have many sub-goals beneath them, measuring reliability, customer service, project completion, regulatory and safety.

RESPONDENT: Michael Daranyi

WITNESS: Dallas Dukes

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 11, 2007

STF 10.11 Please list by amount and account all stock based compensation expense charged to UNS Electric during the test year, including but not limited to executive stock options, the 2006 Omnibus Stock and Incentive Plan, performance share awards, accruals made pursuant to SFAS 123R and any other stock based compensation awards that resulted in costs being charged to UNS Electric during the test year.

a. Also, provide a description of each distinct stock based compensation program that resulted in charges to UNS Electric during the test year.

RESPONSE: Stock based compensation expense charged to UNS Electric during the test year is as follows:

Stock Option Expense

FERC 923	$ 62,904

Performance Share Expense

FERC 923	$ 19,969

Director Stock Award Expense

FERC 930	$ 45,895

Dividend Equivalents on Stock Options & Stock Units

FERC 920	$ 186
FERC 923	$ 33,623
FERC 930	$ (795)
Total	$ 33,014

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 11, 2007**

a. During the test year, Performance Shares and Nonqualified Stock Options were used in the compensation program. Please see STF 10.11, Bates Nos. UNSE(0783)08874 to UNSE(0783)08898, on the enclosed CD for a detailed description of each distinct stock based compensation program that resulted in charges to UNS Electric during the test year.

RESPONDENT: Amy Teller
Human Resources (a)

WITNESS: Karen Kissinger
Dallas Dukes (a)

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007**

STF 3.72 Dues, Industry Associations. Are any amounts included in the test year for payments to industry associations other than those required as membership dues? If so, list the amounts and the accounts in which such contributions are recorded. For each such contribution, also state its purpose and describe how the Company perceives such expense to benefit ratepayers.

RESPONSE: Please see STF 3.72, Bates Nos. UNSE(0783)05154 to UNSE(0783)5155, on the enclosed CD for payments to industry associations other than those required as membership dues. For additional information supporting the Edison Electric Institute ("EEI") membership payment please see the response to STF 3.73.

RESPONDENT: Mina Briggs

WITNESS: Dallas Dukes

STF 3.72 = Due, Industry Associations

ENTERED INVOICES INTO ORACLE A/P
BY COST CENTER
AS OF 02-MAY-07
&FERC
&GL Month
GL Company: 033
&GL Cost Center

Co: 033

Period Name	GI Date - Distribution	Vendor Name	Invoice Number	ET	Invoice Date	Description	Amount	FERC
DEC-05	28-DEC-2005	ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	2006-25	251	29-DEC-2005	RTN CK TO S. CROBBE (SCB09)	$250.00	0930
JUL-05	27-JUL-2005	ARIZONA UTILITY INVESTORS ASSOC	072705 500000	251	27-JUL-2005	RETURN CK TO S. FOLTZ	$2,500.00	0930
AUG-05	03-AUG-2005	ASCET	080305 4000	252	03-AUG-2005	MAIL CHECK	$40.00	0921
JAN-06	26-JAN-2006	AUSA	011706 10000	251	17-JAN-2006	ANNUAL DUES	$100.00	0930
JUL-05	28-JUL-2005	EDISON ELECTRIC INSTITUTE	1-000025467C	251	01-JUL-2005	PO 1343 MEMBERSHIP FEES	$24,071.00	0930
JAN-06	17-JAN-2006		1-000038292	251	14-DEC-2005		$10,000.00	0930
JAN-06	10-JAN-2006		1-000038367	251	14-DEC-2005	PO 1343 MEMBERSHIP FEES	$2,801.90	0930
SEP-05	30-SEP-2005	GOLDEN VALLEY CHAMBER OF COMMERCE	JULY 2005	251	14-SEP-2005	MAIL CHECK	$35.00	0930
OCT-05	21-OCT-2005		07/2005	251	13-OCT-2005	MAIL CHECK	$35.00	0930
OCT-05	14-OCT-2005	KINGMAN MOHAVE LIONS CLUB	1376	251	07-OCT-2005	MAIL CHECK	$60.00	0930
OCT-05	14-OCT-2005		1376CXL	251	07-OCT-2005	MAIL CHECK	$0.00	0930
FEB-06	27-FEB-2006		1446	252	31-JAN-2006		$60.00	0921
AUG-05	12-AUG-2005	KINGMAN ROTARY CLUB	081205 12500	252	12-AUG-2005	MAIL CHECK DUES FOR TOM FERRY	$125.00	0921
NOV-05	07-NOV-2005		102605 12500	251	26-OCT-2005	MAIL CHECK	$125.00	0930
JAN-06	26-JAN-2006		011706 13300	252	17-JAN-2006	quarterly dues/Tom Ferry	$133.00	0921
NOV-05	11-NOV-2005	KINGMAN ROUTE 66 ROTARY CLUB	100105 13250	251	01-OCT-2005	Mail ck	$132.50	0930
FEB-06	21-FEB-2006		020806 25000	252	08-FEB-2006	MAIL CHECK-DUES FOR B. ASPLIN	$250.00	0921
JUN-06	08-JUN-2006		060506 12500	251	05-JUN-2006	MAIL CHECK	$125.00	0930
AUG-05	31-AUG-2005	KINGSMEN	081505 12500	251	15-SEP-2005	MAIL CK	$125.00	0930
NOV-05	11-NOV-2005	KIWANIS CLUB OF LAKE HAVASU	110305 66600	251	03-NOV-2005	MAIL CHECK	$666.00	0930
NOV-05	29-NOV-2005	MOHAVE COMMUNITY COLLEGE	112105 7000	251	21-NOV-2005	MAIL CHECK W/ COPY OF BACKUP	$0.00	0930
AUG-05	03-AUG-2005	MOHAVE MUSEUM OF HISTORY & ARTS	080305 20000	251	03-AUG-2005	MAIL CHECK	$200.00	0930

Σ = $36,572

UNSE(0783)05154

ENTERED INVOICES INTO ORACLE A/P
BY COST CENTER
AS OF 02-MAY-07
&FERC
&GL Month
GL Company: 033
&GL Cost Center

Co: 033

Period Name	GI Date - Distribution	Vendor Name	Invoice Number	ET	Invoice Date	Description	Amount	FERC
JUN-06	16-JUN-2006	NOGALES-SANTA CRUZ CHAMBER OF COMMERCE	060906 6000	251	09-JUN-2006	RTN CK TO N. LUCERO (NOG-E)	$60.00	0930
AUG-05	03-AUG-2005	PETTY CASH	080305 188510	252	03-AUG-2005	RETURN CK TO A. BECKER	$35.00	0921
							Total: $41,929.40	

UNS ELECTRIC, INC.'S RESPONSE TO
MR. MAGRUDER'S SECOND SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 19, 2007

MM DR 2.27 USNE response to STF DR 3.55, excel spreadsheet for FERC account 930.1, on line 3, contains an invoice and payment to the Arizona Mexico Commission of $1750.00 for sponsorship. Could you please explain this expense in terms of the benefits for UNSE customers?

RESPONSE: The $1,750 for the Arizona-Mexico Commission should have been removed from expenses included in the revenue requirement. This invoice was overlooked in error and will be adjusted out of test year expense.

RESPONDENT: Edmond Beck

WITNESS: Edmond Beck

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-06-0783
May 21, 2007

STF 3.55 Advertising Expense. For each of the advertising expense amounts remaining in the test year, please provide an itemization of the amount by advertising campaign/advertisement and provide a copy of the associated advertisement or ad script.

RESPONSE: UNS Electric objects to the use of the word "advertising" as it is vague and ambiguous. Examples of communications between the Company, its customers, and the public are listed below.

Please see STF 3.55 (FERC Account 930.1 Transaction Detail), provided on the enclosed CD, for an itemized list of advertising expenses incurred in the test year. The Excel file is not identified by Bates numbers.

- STF 3.55 (Bernard Hodes) – See file for the UNS Electric open position ads published in newspapers.
- STF 3.55 (Budget Billing) - See files for the art work for bill inserts and/or brochures distributed in the UNS Electric service territory, informing consumers about the Budget Billing program.
- STF 3.55 (Energy Efficiency) - See files for art work for ads, bill inserts and/or brochures distributed, and script for radio spots aired in the UNS Electric service territory, providing information to consumers on ways they can reduce their electric bills.
- STF 3.55 (Electrical Safety) - See for art work for ads, bill inserts and/or brochures distributed, and script for radio spots aired in the UNS Electric service territory, providing safety information to consumers about electricity.
- STF 3.55 (Low-Income) - See files for art work for ads, bill inserts and/or brochures distributed, and script for radio spots aired in the UNS Electric service territory, providing information to consumers on ways they can receive help with paying their electricity bills.
- STF 3.55 (Miscellaneous Communications) - See files for art work for ads, bill inserts and/or brochures distributed in the UNS electric service territory.
- STF 3.55 (Ad Campaigns) - See the Excel worksheet tabs for each Advertising Campaign. Each category provides the consumer

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 21, 2007

communication methods used. The Excel file on the enclosed CD is not identified by Bates numbers

Due to the volume of attachments, UNS Electric is continuing to Bates Number and organize each of these documents and will provide all communications shortly.

RESPONDENT: Kimberly Mayhew

WITNESS: Dallas Dukes

SUPPLEMENTAL RESPONSE:

UNS Electric objects to the use of the word "advertising" as it is vague and ambiguous. Examples of communications between the Company, its customers, and the public are listed below.

Please see STF 3.55 (FERC Account 930.1 Transaction Detail), provided on the enclosed CD, for an itemized list of advertising expenses incurred in the test year. The Excel file is not identified by Bates numbers.

- STF 3.55 (Bernard Hodes) – See file for the UNS Electric open position ads published in newspapers. See Bates Nos. UNSE(0783)08134 to UNSE(0783)08207.

- STF 3.55 (Budget Billing) - See files for the art work for bill inserts and/or brochures distributed in the UNS Electric service territory, informing consumers about the Budget Billing program. See Bates Nos. UNSE(0783)08208 to UNSE(0783)08209.

- STF 3.55 (Electrical Safety) - See for art work for ads, bill inserts and/or brochures distributed, and script for radio spots aired in the UNS Electric service territory, providing safety information to consumers about electricity. See Bates Nos. UNSE(0783)08210 to UNSE(0783)08215.

- STF 3.55 (Energy Efficiency) - See files for art work for ads, bill inserts and/or brochures distributed, and script for radio spots aired in the UNS Electric service territory, providing information to consumers on ways they can reduce their electric bills. See Bates Nos. UNSE(0783)08216 to UNSE(0783)08236.

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 21, 2007

- STF 3.55 (Low-Income) - See files for art work for ads, bill inserts and/or brochures distributed, and script for radio spots aired in the UNS Electric service territory, providing information to consumers on ways they can receive help with paying their electricity bills. See Bates Nos. UNSE(0783)08237 to UNSE(0783)08246.

- STF 3.55 (Miscellaneous Communications) - See files for art work for ads, bill inserts and/or brochures distributed in the UNS electric service territory. See Bates Nos. UNSE(0783)08247 to UNSE(0783)08256.

- STF 3.55 (Ad Campaigns) - See the Excel worksheet tabs for each Advertising Campaign. Each category provides the consumer communication methods used. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

RESPONDENT: Kimberly Mayhew

WITNESS: Dallas Dukes

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007

STF 3.39 Refer to Attachment REW-2, Schedule E. Explain fully why, for accounts 392.xx, Transportation Equipment, Dr. White proposed a 10.0% positive net salvage for each Transportation Equipment account for the similar equipment at UNS Gas (see Attachment REW-2, Statements A and E in the UNS Gas case) versus no positive net salvage for the Transportation Equipment accounts for UNS Electric.

a. Provide all data and analysis Dr. White relied upon for his 10% positive net salvage recommendation for Transportation Equipment at UNS Gas and zero percent for Transportation Equipment at UNS Electric.

b. Please provide a complete detailed listing of the Transportation Equipment in each sub-account to Account 392 at UNS Gas and, separately at UNS Electric.

c. Please explain fully and in detail how the Transportation Equipment at UNS Gas and at UNS Electric is so different as to have a different net salvage recommendation.

d. Did Dr. White review any retirement history for Transportation Equipment at UNS Electric and/or under the previous ownership of the utility? If so, please provide the complete retirement history of Transportation Equipment at UNS Electric and under the previous ownership that Dr. White reviewed.

e. Does UNS Electric have any retirement history for Transportation Equipment at UNS Electric and/or under the previous ownership of the utility? If so, please provide the complete retirement history of Transportation Equipment at UNS Electric and under the previous ownership that UNS and its affiliates have.

f. For each sub-account of Transportation Equipment at UNS Gas and UNS Electric, please provide a detailed listing of all equipment in each such account at 12/31/06.

RESPONSE: Foster Associates inadvertently failed to include a 10 percent net salvage rate for UNS Electric transportation equipment. The impact of this oversight would be a further reduction in 2006 annualized accruals of $143,297. It is the opinion of Foster Associates that the magnitude of the additional reduction does not warrant a refiling of the depreciation study.

RESPONDENT: Dr. Ronald E. White

WITNESS: Dr. Ronald E. White

UNS ELECTRIC, INC.'s RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 14, 2007

STF 11.8 Refer to the response to STF 3.39.

a. Please provide the detailed recalculation of the corrected depreciation rate for Transportation Equipment.

b. Please provide the detailed calculations and workpapers for the $143,297 reduction to the 2006 annualized accrual to reflect a 10 percent net salvage rate for UNS Electric transportation equipment.

RESPONSE:

a. Please see STF 11.8, Bates Nos. UNSE(0783)08910 to UNSE(0783)08919, on the enclosed CD for the detailed recalculation of the corrected depreciation rate to Transportation Equipment.

b. Please see the calculation for the $143,297 reduction below:

14,385,991 – 14,529,288 = (143,297)

RESPONDENT: Dr. Ronald White

WITNESS: Dr. Ronald White

STF 11.8

Statement A

UNS ELECTRIC, INC.
Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	Present Rem. Life	Present Net Salvage	Present Accrual Rate	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H
INTANGIBLE PLANT							
Depreciable							
303.WP Misc. Intangible - WAPA Switchboard	38.00		2.92%	30.16		5.66%	3.13%
Total Depreciable			2.92%	30.16		5.66%	3.13%
Amortizable							
302.00 Franchises and Consents	38.00			← 25 Year Amortization →			
303.00 Miscellaneous Intangible Plant	38.20			← 15 Year Amortization →			
303.WC Misc. Intangible - WAPA Fiber Optic	38.20		4.13%	← 23 Year Amortization →			
303.PC Misc.Intangible Plant - PC Software	31.00		20.00%	← 5 Year Amortization →			
Total Amortizable			4.23%	7.21		61.05%	3.06%
Total Intangible Plant			3.79%	10.88		42.49%	3.09%
OTHER PRODUCTION PLANT							
341.00 Structures and Improvements	38.00		1.38%	29.50		39.14%	2.06%
342.00 Fuel Holders, Producers and Accessories	38.20		2.42%	32.63		18.12%	2.51%
343.00 Prime Movers	37.00		2.34%	26.17		34.01%	2.52%
344.00 Generators	22.60		0.67%	36.15		15.67%	2.33%
345.00 Accessory Electric Equipment	39.50		2.20%	29.39		31.13%	2.34%
346.00 Miscellaneous Power Plant Equipment	31.00		1.87%	33.34		12.06%	2.64%
Total Other Production Plant			2.00%	28.73		29.51%	2.45%
TRANSMISSION PLANT							
350.RW Rights of Way				31.35		36.69%	2.02%
352.00 Structures and Improvements	19.70		3.77%	12.75		60.36%	3.11%
353.00 Station Equipment	23.00		2.92%	21.72		31.60%	3.15%
354.00 Towers and Fixtures	12.40		4.08%	15.92		20.07%	5.02%
355.00 Poles and Fixtures	15.90	-10.0%	5.77%	12.68	-10.0%	53.37%	4.47%
356.00 Overhead Conductors and Devices	30.10		2.71%	23.85		36.63%	2.66%
359.00 Roads and Trails	44.90		2.01%	35.18		29.16%	2.01%
Total Transmission Plant			3.68%	18.90	-2.9%	39.25%	3.41%
DISTRIBUTION PLANT							
360.RW Rights of Way				27.71		43.85%	2.03%
361.00 Structures and Improvements	23.60		3.20%	25.54		24.48%	2.96%
362.00 Station Equipment	15.30		4.82%	11.54		52.96%	4.08%
364.00 Poles, Towers and Fixtures	18.90	-10.0%	4.23%	14.83	-10.0%	48.82%	4.13%
✓365.00 Overhead Conductors and Devices	18.40	-10.0%	4.36%	15.16	-10.0%	47.56%	4.12%
366.00 Underground Conduit	21.50		4.28%	18.66	-5.0%	34.45%	3.78%
367.00 Underground Conductors and Devices	14.30		5.36%	14.20		37.63%	4.39%
✓368.00 Line Transformers	14.20	-5.0%	4.93%	13.46	-5.0%	42.84%	4.62%
✓369.OH Services - Overhead	18.30		4.23%	14.43		45.79%	3.76%
369.UG Services - Underground	18.30		4.23%	16.26		39.13%	3.74%
370.00 Meters	26.20	-5.0%	3.25%	24.14	-5.0%	30.09%	3.10%
373.00 Street Lighting and Signal Systems	17.40		4.55%	16.64		32.89%	4.03%
Total Distribution Plant			4.50%	14.75	-6.0%	44.90%	4.15%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	27.80		2.89%	29.03		23.22%	2.64%
392.C1 Transportation Equipment - Class 1			25.00%	4.00	10.0%	44.07%	11.48%
392.C2 Transportation Equipment - Class 2			25.00%	3.02	10.0%	43.82%	15.29%
392.C3 Transportation Equipment - Class 3			25.00%	3.28	10.0%	28.71%	18.69%
392.C4 Transportation Equipment - Class 4			12.50%	1.63	10.0%	70.49%	11.97%
392.C5 Transportation Equipment - Class 5			12.50%	6.58	10.0%	15.71%	11.29%
396.00 Power Operated Equipment	8.80		3.33%	5.16		64.53%	6.87%
Total Depreciable			12.12%	4.13	6.9%	49.82%	10.29%

UNS ELECTRIC, INC.

Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	Present Rem. Life	Present Net Salvage	Present Accrual Rate	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H
Amortizable							
391.10 Office Furniture and Equipment	17.60		3.72%	← 21 Year Amortization →			
391.20 Computer Equipment - PCs			20.00%	← 5 Year Amortization →			
393.00 Stores Equipment	28.10		2.62%	← 33 Year Amortization →			
394.00 Tools, Shop and Garage Equipment	23.80		3.02%	← 29 Year Amortization →			
395.00 Laboratory Equipment	33.30		2.41%	← 40 Year Amortization →			
397.CE Communication Equipment	17.60		4.13%	← 23 Year Amortization →			
398.00 Miscellaneous Equipment	11.60		5.45%	← 18 Year Amortization →			
Total Amortizable			5.10%	11.20		41.95%	3.65%
Total General Plant			8.97%	6.21	-4.7%	46.29%	7.31%
TOTAL UTILITY			4.53%	14.29	-4.7%	43.58%	4.14%

UNS ELECTRIC, INC.

Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/05 Plant Investment	2006 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
INTANGIBLE PLANT				
Depreciable				
303.WP Misc. Intangible - WAPA Switchboard	$3,558,415	$103,906	$111,378	$7,472
Total Depreciable	$3,558,415	$103,906	$111,378	$7,472
Amortizable				
302.00 Franchises and Consents	$11,908		$54	$54
303.00 Miscellaneous Intangible Plant	4,219,098		141,762	141,762
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000	69,591	73,298	3,707
303.PC Misc.Intangible Plant - PC Software	1,145,223	229,045	1,145	(227,900)
Total Amortizable	$7,061,229	$298,636	$216,259	($82,377)
Total Intangible Plant	$10,619,644	$402,542	$327,637	($74,905)
OTHER PRODUCTION PLANT				
341.00 Structures and Improvements	$619,244	$8,546	$12,756	$4,210
342.00 Fuel Holders, Producers and Accessories	631,364	15,279	15,847	568
343.00 Prime Movers	8,684,079	203,207	218,839	15,632
344.00 Generators	2,309,132	15,471	53,803	38,332
345.00 Accessory Electric Equipment	1,685,197	37,074	39,434	2,360
346.00 Miscellaneous Power Plant Equipment	493,979	9,237	13,041	3,804
Total Other Production Plant	$14,422,995	$288,814	$353,720	$64,906
TRANSMISSION PLANT				
350.RW Rights of Way	$346,016		$6,990	$6,990
352.00 Structures and Improvements	191,668	7,226	5,961	(1,265)
353.00 Station Equipment	17,657,646	515,603	556,216	40,613
354.00 Towers and Fixtures	521,825	21,290	26,196	4,906
355.00 Poles and Fixtures	12,285,169	708,854	549,147	(159,707)
356.00 Overhead Conductors and Devices	11,245,657	304,757	299,134	(5,623)
359.00 Roads and Trails	183,860	3,696	3,696	
Total Transmission Plant	$42,431,841	$1,561,426	$1,447,340	($114,086)
DISTRIBUTION PLANT				
360.RW Rights of Way	$86,619		$1,758	$1,758
361.00 Structures and Improvements	3,398,247	108,744	100,588	(8,156)
362.00 Station Equipment	28,402,465	1,368,999	1,158,821	(210,178)
364.00 Poles, Towers and Fixtures	75,596,882	3,197,748	3,122,151	(75,597)
365.00 Overhead Conductors and Devices	48,310,770	2,106,350	1,990,404	(115,946)
366.00 Underground Conduit	12,126,868	519,030	458,396	(60,634)
367.00 Underground Conductors and Devices	22,976,392	1,231,535	1,008,664	(222,871)
368.00 Line Transformers	45,658,424	2,250,960	2,109,419	(141,541)
369.OH Services - Overhead	7,297,945	308,703	274,403	(34,300)
369.UG Services - Underground	3,315,090	140,228	123,984	(16,244)
370.00 Meters	9,368,222	304,467	290,415	(14,052)
373.00 Street Lighting and Signal Systems	3,769,729	171,523	151,920	(19,603)
Total Distribution Plant	$260,307,653	$11,708,287	$10,790,923	($917,364)

UNS ELECTRIC, INC.

Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/05 Plant Investment	2006 Annualized Accrual		
		Present	Proposed	Difference
A	B	C	D	E=D-C
GENERAL PLANT				
Depreciable				
390.00 Structures and Improvements	$2,445,738	$70,682	$64,567	($6,115)
392.C1 Transportation Equipment - Class 1	366,331	91,583	42,055	(49,528)
392.C2 Transportation Equipment - Class 2	882,290	220,573	134,902	(85,671)
392.C3 Transportation Equipment - Class 3	1,007,316	251,829	188,267	(63,562)
392.C4 Transportation Equipment - Class 4	4,808,218	601,027	575,544	(25,483)
392.C5 Transportation Equipment - Class 5	584,467	73,058	65,986	(7,072)
396.00 Power Operated Equipment	968,258	32,243	66,519	34,276
Total Depreciable	$11,062,618	$1,340,995	$1,137,840	($203,155)
Amortizable				
391.10 Office Furniture and Equipment	$2,297,349	$85,461	$103,610	$18,149
391.20 Computer Equipment - PCs	868,777	173,755	15,030	(158,725)
393.00 Stores Equipment	122,871	3,219	3,698	479
394.00 Tools, Shop and Garage Equipment	2,391,755	72,231	79,406	7,175
395.00 Laboratory Equipment	808,108	19,475	20,203	728
397.CE Communication Equipment	2,391,716	98,778	100,691	1,913
398.00 Miscellaneous Equipment	114,643	6,248	5,893	(355)
Total Amortizable	$8,995,219	$459,167	$328,531	($130,636)
Total General Plant	$20,057,837	$1,800,162	$1,466,371	($333,791)
TOTAL UTILITY	$347,839,970	$15,761,231	$14,385,991	($1,375,240)

UNS ELECTRIC, INC.
Depreciation Reserve Summary
Broad Group Procedure
December 31, 2005

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
Depreciable							
303.WP Misc. Intangible - WAPA Switchboard	$3,558,415	$238,117	6.69%	$204,609	5.75%	$201,261	5.66%
Total Depreciable	$3,558,415	$238,117	6.69%	$204,609	5.75%	$201,261	5.66%
Amortizable							
302.00 Franchises and Consents	$11,908	$0		$11,775	98.88%	$11,775	98.88%
303.00 Miscellaneous Intangible Plant	4,219,098	267,350	6.34%	2,971,824	70.44%	2,971,824	70.44%
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000	159,478	9.46%	183,152	10.87%	183,152	10.87%
303.PC Misc.Intangible Plant - PC Software	1,145,223	1,178,678	102.92%	1,144,041	99.90%	1,144,041	99.90%
Total Amortizable	$7,061,229	$1,605,507	22.74%	$4,310,792	61.05%	$4,310,792	61.05%
Total Intangible Plant	$10,619,644	$1,843,624	17.36%	$4,515,401	42.52%	$4,512,053	42.49%
OTHER PRODUCTION PLANT							
341.00 Structures and Improvements	$619,244	$367,625	59.37%	$246,434	39.80%	$242,402	39.14%
342.00 Fuel Holders, Producers and Accessories	631,364	121,053	19.17%	116,329	18.43%	114,426	18.12%
343.00 Prime Movers	8,684,079	2,637,958	30.38%	3,002,520	34.58%	2,953,395	34.01%
344.00 Generators	2,309,132	254,855	11.04%	367,850	15.93%	361,832	15.67%
345.00 Accessory Electric Equipment	1,685,197	450,671	26.74%	533,384	31.65%	524,658	31.13%
346.00 Miscellaneous Power Plant Equipment	493,979	71,873	14.55%	60,577	12.26%	59,586	12.06%
Total Other Production Plant	$14,422,995	$3,904,034	27.07%	$4,327,095	30.00%	$4,256,297	29.51%
TRANSMISSION PLANT							
350.RW Rights of Way	$346,016	$1		$129,064	37.30%	$126,952	36.69%
352.00 Structures and Improvements	191,668	147,919	77.17%	117,614	61.36%	115,690	60.36%
353.00 Station Equipment	17,657,646	6,525,850	36.96%	5,672,519	32.13%	5,579,708	31.60%
354.00 Towers and Fixtures	521,825	144,146	27.62%	106,452	20.40%	104,711	20.07%
355.00 Poles and Fixtures	12,285,169	6,414,872	52.22%	6,665,775	54.26%	6,556,714	53.37%
356.00 Overhead Conductors and Devices	11,245,657	4,276,151	38.02%	4,187,528	37.24%	4,119,014	36.63%
359.00 Roads and Trails	183,860	73,249	39.84%	54,496	29.64%	53,604	29.16%
Total Transmission Plant	$42,431,841	$17,582,187	41.44%	$16,933,449	39.91%	$16,656,393	39.25%
DISTRIBUTION PLANT							
360.RW Rights of Way	$86,619	$0		$38,615	44.58%	$37,983	43.85%
361.00 Structures and Improvements	3,398,247	824,191	24.25%	845,564	24.88%	831,729	24.48%
362.00 Station Equipment	28,402,465	14,346,966	50.51%	15,291,887	53.84%	15,041,690	52.96%

UNS ELECTRIC, INC.
Depreciation Reserve Summary
Broad Group Procedure
December 31, 2005

Statement C

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
364.00 Poles, Towers and Fixtures	75,596,882	35,977,383	47.59%	37,523,576	49.64%	36,909,637	48.82%
365.00 Overhead Conductors and Devices	48,310,770	22,914,406	47.43%	23,357,935	48.35%	22,975,766	47.56%
366.00 Underground Conduit	12,126,868	4,060,572	33.48%	4,247,436	35.03%	4,177,941	34.45%
367.00 Underground Conductors and Devices	22,976,392	9,724,089	42.32%	8,790,967	38.26%	8,647,135	37.63%
368.00 Line Transformers	45,658,424	21,572,430	47.25%	19,885,236	43.55%	19,559,885	42.84%
369.OH Services - Overhead	7,297,945	3,359,775	46.04%	3,397,599	46.56%	3,342,009	45.79%
369.UG Services - Underground	3,315,090	1,044,451	31.51%	1,318,669	39.78%	1,297,094	39.13%
370.00 Meters	9,368,222	2,871,949	30.66%	2,865,926	30.59%	2,819,036	30.09%
373.00 Street Lighting and Signal Systems	3,769,729	1,250,480	33.17%	1,260,597	33.44%	1,239,972	32.89%
Total Distribution Plant	$260,307,653	$117,946,692	45.31%	$118,824,008	45.65%	$116,879,878	44.90%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$2,445,738	$800,583	32.73%	$577,323	23.61%	$567,877	23.22%
392.C1 Transportation Equipment - Class 1	366,331	274,470	74.92%	164,116	44.80%	161,431	44.07%
392.C2 Transportation Equipment - Class 2	882,290	615,312	69.74%	393,051	44.55%	386,620	43.82%
392.C3 Transportation Equipment - Class 3	1,007,316	706,361	70.12%	294,023	29.19%	289,213	28.71%
392.C4 Transportation Equipment - Class 4	4,808,218	4,578,490	95.22%	3,445,689	71.66%	3,389,313	70.49%
392.C5 Transportation Equipment - Class 5	584,467	95,384	16.32%	93,369	15.98%	91,841	15.71%
396.00 Power Operated Equipment	968,258	732,737	75.68%	635,177	65.60%	624,785	64.53%
Total Depreciable	$11,062,618	$7,803,339	70.54%	$5,602,749	50.65%	$5,511,080	49.82%
Amortizable							
391.10 Office Furniture and Equipment	$2,297,349	$764,125	33.26%	$912,876	39.74%	$912,876	39.74%
391.20 Computer Equipment - PCs	868,777	62,880	7.24%	851,825	98.05%	851,825	98.05%
393.00 Stores Equipment	122,871	57,010	46.40%	68,689	55.90%	68,689	55.90%
394.00 Tools, Shop and Garage Equipment	2,391,755	950,482	39.74%	1,096,139	45.83%	1,096,139	45.83%
395.00 Laboratory Equipment	808,108	198,068	24.51%	286,621	35.47%	286,621	35.47%
397.CE Communication Equipment	2,391,716	387,217	16.19%	473,306	19.79%	473,306	19.79%
398.00 Miscellaneous Equipment	114,643	89,560	78.12%	84,062	73.33%	84,062	73.33%
Total Amortizable	$8,995,219	$2,509,343	27.90%	$3,773,518	41.95%	$3,773,518	41.95%
Total General Plant	$20,057,837	$10,312,681	51.41%	$9,376,267	46.75%	$9,284,598	46.29%
TOTAL UTILITY	$347,839,970	$151,589,220	43.58%	$153,976,220	44.27%	$151,589,220	43.58%

6/5/2007

UNS ELECTRIC, INC.
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
INTANGIBLE PLANT									
Depreciable									
303.WP Misc. Intangible - WAPA Switchboard	$3,558,415		$3,558,415						
Total Depreciable	$3,558,415		$3,558,415						
Amortizable									
302.00 Franchises and Consents	$11,908		$11,908						
303.00 Miscellaneous Intangible Plant	4,219,099	1	4,219,098						
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000		1,685,000						
303.PC Misc.Intangible Plant - PC Software	1,145,223		1,145,223						
Total Amortizable	$7,061,230	$1	$7,061,229						
Total Intangible Plant	$10,619,645	$1	$10,619,644						
OTHER PRODUCTION PLANT									
341.00 Structures and Improvements	$619,244		$619,244						
342.00 Fuel Holders, Producers and Accessories	631,364		631,364						
343.00 Prime Movers	10,707,541	2,023,462	8,684,079						
344.00 Generators	2,356,732	47,600	2,309,132						
345.00 Accessory Electric Equipment	1,904,534	219,337	1,685,197						
346.00 Miscellaneous Power Plant Equipment	503,598	9,619	493,979						
Total Other Production Plant	$16,723,013	$2,300,018	$14,422,995						
TRANSMISSION PLANT									
350.RW Rights of Way	$346,016		$346,016						
352.00 Structures and Improvements	191,668		191,668						
353.00 Station Equipment	17,697,125	39,479	17,657,646						
354.00 Towers and Fixtures	521,825		521,825						
355.00 Poles and Fixtures	12,393,414	108,245	12,285,169		-10.0%		(1,228,517)	(1,228,517)	-9.9%
356.00 Overhead Conductors and Devices	11,267,316	21,659	11,245,657						
359.00 Roads and Trails	183,860		183,860						
Total Transmission Plant	$42,601,224	$169,383	$42,431,841		-2.9%		($1,228,517)	($1,228,517)	-2.9%
DISTRIBUTION PLANT									
360.RW Rights of Way	$86,619		$86,619						
361.00 Structures and Improvements	3,409,388	11,141	3,398,247						
362.00 Station Equipment	28,425,896	23,431	28,402,465						
364.00 Poles, Towers and Fixtures	76,698,862	1,101,780	75,596,882	-0.8%	-10.0%	(8,814)	(7,559,688)	(7,568,502)	-9.9%
365.00 Overhead Conductors and Devices	49,287,987	977,217	48,310,770	-1.8%	-10.0%	(17,590)	(4,831,077)	(4,848,667)	-9.8%
366.00 Underground Conduit	12,235,191	108,323	12,126,868	0.1%	-5.0%	108	(606,343)	(606,235)	-5.0%
367.00 Underground Conductors and Devices	23,284,235	307,843	22,976,392	-0.8%		(2,463)		(2,463)	
368.00 Line Transformers	47,077,581	1,419,157	45,658,424	-5.9%	-5.0%	(83,730)	(2,282,921)	(2,366,651)	-5.0%
369.OH Services - Overhead	7,297,945		7,297,945						
369.UG Services - Underground	3,315,090		3,315,090						
370.00 Meters	9,760,332	392,110	9,368,222		-5.0%		(468,411)	(468,411)	-4.8%
373.00 Street Lighting and Signal Systems	3,640,377	70,648	3,769,729						
Total Distribution Plant	$264,719,303	$4,411,650	$260,307,653	-2.5%	-6.0%	($112,489)	($15,748,441)	($15,860,930)	-6.0%

6/5/2007

UNS ELECTRIC, INC.
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$2,445,743	$5	$2,445,738						
392.C1 Transportation Equipment - Class 1	456,297	89,966	366,331	8.0%	10.0%	7,197	36,633	43,830	9.6%
392.C2 Transportation Equipment - Class 2	1,163,990	301,700	862,290	9.0%	10.0%	27,153	88,229	115,362	9.7%
392.C3 Transportation Equipment - Class 3	1,802,214	794,898	1,007,316	3.9%	10.0%	31,001	100,732	131,733	7.3%
392.C4 Transportation Equipment - Class 4	4,853,150	44,932	4,808,218	12.9%	10.0%	5,796	480,822	486,618	10.0%
392.C5 Transportation Equipment - Class 5	584,467		584,467		10.0%		58,447	58,447	10.0%
396.00 Power Operated Equipment	968,258		968,258						
Total Depreciable	$12,294,119	$1,231,501	$11,062,618	5.8%	6.9%	$71,148	$764,862	$836,010	6.8%
Amortizable									
391.10 Office Furniture and Equipment	$5,955,915	$3,658,566	$2,297,349						
391.20 Computer Equipment - PCs	868,777		868,777						
393.00 Stores Equipment	122,871		122,871						
394.00 Tools, Shop and Garage Equipment	2,455,025	63,270	2,391,755						
395.00 Laboratory Equipment	864,222	56,114	808,108						
397.CE Communication Equipment	2,432,124	40,408	2,391,718						
398.00 Miscellaneous Equipment	114,643		114,643						
Total Amortizable	$12,813,577	$3,818,358	$8,995,219						
Total General Plant	$25,107,696	$5,049,859	$20,057,837	1.4%	3.8%	$71,148	$764,862	$836,010	3.3%
TOTAL UTILITY	$359,770,881	$11,930,911	$347,839,970	-0.3%	-4.7%	($41,341)	($16,212,096)	($16,253,437)	-4.5%

6/5/2007

UNS ELECTRIC, INC.
Present and Proposed Parameters
Broad Group Procedure

Statement E

Account Description	Present Parameters						Proposed Parameters					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
Depreciable												
303.WP Misc. Intangible - WAPA Switchboard	49.00	S6	49.00	38.00			32.00	R1	32.00	30.16		
Total Depreciable									32.00	30.16		
Amortizable												
302.00 Franchises and Consents	49.00	S6	49.00	38.00			25.00	SQ	25.00	2.50		
303.00 Miscellaneous Intangible Plant	40.00	S4	40.00	38.20			15.00	SQ	15.00	8.81		
303.WO Misc. Intangible - WAPA Fiber Optic	40.00	S4	40.00	38.20			23.00	SQ	23.00	20.50		
303.PC Misc.Intangible Plant - PC Software	36.00	R1	36.00	31.00			5.00	SQ	5.00	1.00		
Total Amortizable									12.09	7.21		
Total Intangible Plant									15.27	10.88		
OTHER PRODUCTION PLANT												
341.00 Structures and Improvements	49.00	S6	49.00	38.00			49.00	S6	49.00	29.50		
342.00 Fuel Holders, Producers and Accessories	40.00	S4	40.00	38.20			40.00	S4	40.00	32.63		
343.00 Prime Movers	40.00	R3	40.00	37.00			40.00	R3	40.00	26.17		
344.00 Generators	43.00	S0	43.00	22.60			43.00	S0	43.00	36.15		
345.00 Accessory Electric Equipment	43.00	S6	43.00	39.50			43.00	S6	43.00	29.39		
346.00 Miscellaneous Power Plant Equipment	38.00	R1	36.00	31.00			38.00	R1	38.00	33.34		
Total Other Production Plant									41.04	28.73		
TRANSMISSION PLANT												
350.RW Rights of Way							50.00	SQ	50.00	31.35		
352.00 Structures and Improvements	33.00	R3	33.00	19.70			33.00	R3	33.00	12.75		
353.00 Station Equipment	32.00	R1	32.00	23.00			32.00	R1	32.00	21.72		
354.00 Towers and Fixtures	20.00	L0	20.00	12.40			20.00	L0	20.00	15.92		
355.00 Poles and Fixtures	25.00	S5	25.00	15.90	-10.0	-10.0	25.00	S5	25.00	12.68	-9.9	-10.0
356.00 Overhead Conductors and Devices	38.00	L3	38.00	30.10			38.00	L3	38.00	23.85		
359.00 Roads and Trails	50.00	SQ	50.00	44.90			50.00	SQ	50.00	35.18		
Total Transmission Plant									30.71	18.90	-2.9	-2.9
DISTRIBUTION PLANT												
360.RW Rights of Way							50.00	SQ	50.00	27.71		
361.00 Structures and Improvements	34.00	R4	34.00	23.60			34.00	R4	34.00	25.54		
362.00 Station Equipment	25.00	S4	25.00	15.30			25.00	S4	25.00	11.54		
364.00 Poles, Towers and Fixtures	27.00	S4	27.00	18.90	-10.0	-10.0	27.00	S4	27.00	14.83	-9.9	-10.0
365.00 Overhead Conductors and Devices	27.00	S3	27.00	18.40	-10.0	-10.0	27.00	S3	27.00	15.16	-9.8	-10.0

6/5/2007

UNS ELECTRIC, INC.
Present and Proposed Parameters
Broad Group Procedure

Statement E

Account Description	Present Parameters						Proposed Parameters					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
366.00 Underground Conduit	28.00	S2	26.00	21.50			28.00	S2	28.00	18.66	-5.0	-5.0
367.00 Underground Conductors and Devices	23.00	S3	23.00	14.30			23.00	S3	23.00	14.20		
368.00 Line Transformers	23.00	S4	23.00	14.20	-5.0	-5.0	23.00	S4	23.00	13.46	-5.0	-5.0
369.OH Services - Overhead	27.00	R5	27.00	18.30			27.00	R5	27.00	14.43		
369.UG Services - Underground	27.00	R5	27.00	18.30			27.00	R5	27.00	16.26		
370.00 Meters	34.00	R3	34.00	26.20	-5.0	-5.0	34.00	R3	34.00	24.14	-4.8	-5.0
373.00 Street Lighting and Signal Systems	25.00	S4	25.00	17.40			25.00	S4	25.00	16.64		
Total Distribution Plant									25.87	14.75	-6.0	-6.0
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	38.00	R2	36.00	27.80			38.00	R2	38.00	29.03		
392.C1 Transportation Equipment - Class 1							8.00	L1.5	8.00	4.00	9.6	10.0
392.C2 Transportation Equipment - Class 2							6.00	L2	6.00	3.02	9.7	10.0
392.C3 Transportation Equipment - Class 3							5.00	S5	5.00	3.28	7.3	10.0
392.C4 Transportation Equipment - Class 4							8.00	S4	8.00	1.63	10.0	10.0
392.C5 Transportation Equipment - Class 5							8.00	S4	8.00	6.58	10.0	10.0
396.00 Power Operated Equipment	15.00	S5	15.00	6.80			15.00	S5	15.00	5.16		
Total Depreciable									9.24	4.13	6.8	6.9
Amortizable												
391.10 Office Furniture and Equipment	21.00	R2	21.00	17.60			21.00	SQ	21.00	13.37		
391.20 Computer Equipment - PCs	5.00		5.00				5.00	SQ	5.00	1.13		
393.00 Stores Equipment	33.00	S6	33.00	28.10			33.00	SQ	33.00	14.67		
394.00 Tools, Shop and Garage Equipment	29.00	S-.5	29.00	23.80			29.00	SQ	29.00	16.32		
395.00 Laboratory Equipment	40.00	R4	40.00	33.30			40.00	SQ	40.00	25.85		
397.CE Communication Equipment	23.00	R1.5	23.00	17.60			23.00	SQ	23.00	19.07		
398.00 Miscellaneous Equipment	18.00	R4	18.00	11.60			18.00	SQ	18.00	5.19		
Total Amortizable									17.99	11.20		
Total General Plant									11.82	6.21	-4.5	-4.7
TOTAL UTILITY									24.51	14.29	-4.5	-4.7

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007

STF 3.70 Cost-saving Programs. Please list and describe in detail any cost-saving programs implemented during the period 2005 through the present. For each program listed in response to this request, show the anticipated and achieved savings. Include calculations of savings amounts and explain any assumptions used in such calculations. For each cost-saving program listed, provide the cost-benefit analyses for each program. Show the impact of each such cost-saving program on the test year.

RESPONSE: Meter Reading Services:
UNS Electric entered into a meter reading services agreement with SES in February 2005. The term of the agreement is three (3) years. The contractor reads electric meters in Kingman and Lake Havasu City service territories.

The average monthly invoice for meter reading services has been reduced by approximately $10,000 from UNS Electric's prior meter reading services provider (GuardForce).

RESPONDENT: Paula Baxter

WITNESS: Thomas Ferry

UNS ELECTRIC, INC.'S RESPONSES TO STAFF'S TENTH SET OF DATA REQUESTS DOCKET NO. E-04204A-06-0783 June 11, 2007

STF 10.4 Were there any charges from Southwest Energy Services directly to UNS Electric during the test year? If so, please provide the amounts by account for all such charges, and provide comparable information for calendar 2005 and 2006.

RESPONSE: Southwest Energy Services ("SES") submitted invoices to UNS Electric totaling $637,813 for services provided in 2005, and $772,853 for services provided in 2006. Some of these invoices included services for UNS Gas, Inc. ("UNS Gas") and UNS Electric charged these amounts to UNS Gas accordingly. The following is a summary of how these invoices were charged during the test-year. Also included is comparable data for 2005 and 2006.

Test-Year Ended June 30, 2006	
UNE FERC 107	$ 208
UNE FERC 163	$ 34,539
UNE FERC 902	$ 547,400
UNE FERC 903	$ 6,746
Charged to UNS Gas	$ 101,065
Total	$ 689,958
2005 Invoices	
UNE FERC 163	$ 56,780
UNE FERC 902	$ 515,562
Charged to UNS Gas	$ 65,471
Total	$ 637,813
2006 Invoices	
UNE FERC 107	$ 3,282
UNE FERC 163	$ 32,095
UNE FERC 596	$ 15,701
UNE FERC 902	$ 591,550
UNE FERC 903	$ 8,411
Charged to TEP in error ***	$ 27,169
Charged to UNS Gas	$ 94,645
Total	$ 772,853

*** This invoice was charged to and paid by Tucson Electric Power Company ("TEP") in error. It should have been charged to UNE FERC 902

RESPONDENT: Amy Teller

WITNESS: Karen Kissinger

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TENTH SET OF DATA REQUESTS
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June 11, 2007

STF 10.5 Were there any charges from Southwest Energy Services indirectly from TEP or another affiliate to UNS Electric during the test year? If so, please provide the amounts by account for all such charges, and provide comparable information for calendar 2005 and 2006.

RESPONSE: SES provides services to TEP on a regular basis. Some of these invoices include services for UNS Electric which are charged to UNS Electric accordingly. The following is a summary of TEP's SES invoices charged to UNS Electric during the test-year. Also included is comparable data for 2005 and 2006.

Test-Year Ended June 30, 2006	
UNE FERC 107	$ 27,981
UNE FERC 163	$ 3,155
UNE FERC 184	$ 8,009
UNE FERC 583	$ 11
UNE FERC 588	$ 4,178
UNE FERC 595	$ 1,203
UNE FERC 596	$ 806
Total	$ 45,343
2005	
UNE FERC 107	$ 9,110
UNE FERC 163	$ 56
UNE FERC 184	$ 910
UNE FERC 583	$ 11
UNE FERC 588	$ 2,093
UNE FERC 595	$ 217
Total	$ 12,397
2006	
UNE FERC 107	$ 29,501
UNE FERC 108	$ 718
UNE FERC 163	$ 3,473
UNE FERC 184	$ 27,243
UNE FERC 588	$ 43,825
UNE FERC 595	$ 1,531
UNE FERC 903	$ 333
Total	$ 106,624

RESPONDENT: Amy Teller

WITNESS: Karen Kissinger

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TENTH SET OF DATA REQUESTS
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STF 10.6 When Southwest Energy Services provides supplemental work force services for UNS Electric, TEP or other affiliates, is there any markup above payroll cost included in such charges? If so, please describe how the billing rates for SES supplemental work force are determined and identify all components of such rates above the base payroll cost paid by SES.

RESPONSE: When SES provides supplemental work force services to UNS Electric, TEP or other affiliates, SES charges a 10% mark-up on the base wages of the supplemental worker.

In addition, SES charges the cost of employer's taxes, workers' compensation and benefits. For example, for a supplemental administrative assistant that is paid $12.00 per hour, SES would charge ($12.00 + $1.20 markup) per hour; plus employer's taxes, workers' compensation, and benefits (cost).

RESPONDENT: Bob Dame

WITNESS: Karen Kissinger

**UNS ELECTRIC, INC.'s RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 14, 2007**

STF 11.10 Refer to the response to STF 3.70.

a. Please provide the contract with SES.

b. What is the total expense to UNS Electric for the test year, by account, for the meter reading services provided by SES?

c. Is SES an affiliated company? If so, please answer parts d through i.

d. Please show in detail how the pricing for SES services to be provided to UNS Electric was developed.

e. What is the profit margin to SES for the meter reading services it provides to UNS Electric?

f. Does SES have audited or unaudited financial statements? Please provide such statements for 2005 and 2006.

g. Does SES have earnings statements or balance sheets? Please provide such documents for 2005 and 2006.

h. What is the markup over cost for the meter reading services that SES provides to UNS Electric? Provide for 2005 and 2006.

i. How is the markup over cost for the meter reading services that SES provides to UNS Electric determined? Show calculations for 2005 and 2006.

RESPONSE:

a. Please see the response to STF 3.58, Bates Nos. UNSE(0783)05042 through UNSE(0783)05046 for a copy of the meter reading services contract with SES.

b. Please see STF 11.10 (b) on the enclosed CD for the meter reading expense in FERC 902 provided by SES. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

c. Yes, SES is an affiliated company.

d. Please see STF 11.10(d), Bates No. UNSE(0783)08920, on the enclosed CD for the original estimate on how much it would cost to operate the business unit and how much SES would have to charge per read. SES was competing against the former vendor who was doing the reads at $.65 the previous year. SES ended up going with the $.65 knowing it was a little under what was needed, but had to remain competitive with the market. SES began reading

UNS ELECTRIC, INC.'s RESPONSES TO
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UniSource Energy Service, Inc.'s electric meter reads in February 2005.

e. There is no profit margin directly included in the "per read" charges assessed to UNS Electric by SES. Using the competitive "per read" rate, SES After-Tax profit was projected at 5.5%. In 2005, the actual After-Tax profit was $13,000 or 1.9% and in 2006 the After-Tax profit was $42,000 or 4.6% (2006 includes income and operating expenses for the City of Kingman Water Meter Reading that began in August of 2006).

f., g. SES does not have audited financial statements. Please see STF 11.10 (f-g) on the enclosed CD for the SES balance sheets as of December 31, 2005 and 2006 and the SES income statements for the years ended December 31, 2005 and 2006. STF 11.10 (f & g) contains confidential information and is being provided pursuant to the terms of the Protective Agreement. The Excel file on the enclosed CD is not identified by Bates numbers.

h. As demonstrated in the above statements, the markup over cost for 2005 was $13,000 and for 2006 was $42,000. The City of Kingman Water Meter Reads are included in 2006.

i. Per the three year contract, SES increases the billing rate $.02 per read, per year. In 2005 the rate was $.65 per read, in 2006 it was increased to $.67 per read and in 2007 it is currently $.69 per read. The $.02 increase represents a budgeted increase of 3% each year to off-set the cost of wage increases.

RESPONDENT: Mina Briggs, Janet Zaidenberg-Schrum, Bob Dame and Tom Ferry

WITNESS: Tom Ferry

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S FIFTEENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 26, 2007

STF 15.1 Southwest Energy Services (SES) charges. Refer to the responses to STF 10.4, STF 10.5, and STF 10.6.

a. The response to STF 10.6 indicates that "SES charges a 10% mark-up on the base wages of the supplemental worker." For each of the amounts of SES charges listed on the responses to STF 10.4 and STF 10.5, please identify the amount of the SES 10% mark-up over base wages. If exact amounts are not available, please provide the Company's best estimates of the SES 10% mark-up charges and show how such estimates were derived.

b. Do the SES charges to UNS Electric listed in the responses to STF 10.4 and STF 10.5 include any incentive compensation in the benefits cost? If so, please identify the amount of incentive compensation included in the SES charges to UNS Electric listed in the responses to STF 10.4 and STF 10.5.

c. Please list the benefits cost, by type of benefit, that is included in the SES charges to UNS Electric.

d. Is the 10% SES mark-up over base wages specified in a written contract? If so, please provide the contract, and indicate specifically where in the contract the 10% markup is specified.

RESPONSE: UNS Electric is in the process of gathering information and will provide the response to this data request as soon as the compilation is complete.

UNS ELECTRIC, INC.'S RESPONSES TO
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STF 3.19 Please provide all of the Company's actuarial service life data, which was sorted by age, in Excel if available or in Excel-readable format if not already in Excel.

RESPONSE: Please see STF 3.19 (Database) on the enclosed CD. The Excel file on the enclosed CD is not identified by Bates numbers.

RESPONDENT: Dr. Ronald E. White

WITNESS: Dr. Ronald E. White

UNS ELECTRIC, INC.'S RESPONSES TO
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May 17, 2007

STF 3.30 For each plant account, please provide the actual cost of removal and net salvage information for each year, 2000 through 2005.

RESPONSE: Please see the response to STF 3.19. Neither Foster Associates nor UNS Electric has actual cost of removal and net salvage information for calendar years other than 2005.

RESPONDENT: Dr. Ronald E. White

WITNESS: Dr. Ronald E. White

UNS ELECTRIC, INC.'s RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
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STF 11.2 CWIP and Black Mountain Generating Station

a. Does any portion of the Company's request for $10,761,154 of CWIP in rate base (Adjustment UNSE-3) relate to the Black Mountain Generating Station?

b. If so, please identify all amounts included in the Company's request for $10,761,154 of CWIP in rate base that relate to the Black Mountain Generating Station.

c. Does any portion of the Company's proposed pro forma adjustments (shown on Schedule C-2, page 4, lines 7 and 8) for depreciation and property taxes, respectively, relate to the Black Mountain Generating Station?

d. If so, please identify all amounts included in the Company's proposed pro forma adjustments for depreciation and property taxes, respectively, that relate to the Black Mountain Generating Station.

RESPONSE:

a. No.

b. Not applicable.

c. No.

d. Not applicable.

RESPONDENT: Carl Dabelstein

WITNESS: Karen Kissinger

EXHIBITS

E-04204A-06-0783

PART 1 OF 5
BAR CODE # 0000068370

To review remaining parts please see the following:

PART 2 OF 5 BAR CODED #0000068363

PART 3 OF 5 BAR CODED #0000068364

PART 4 OF 5 BAR CODED #0000068365

PART 5 OF 5 BAR CODED #0000068366