OGE ENERGY CORP
Form 8-K
December 16, 2005

**UNITED STATES**

**SECURITIES AND EXCHANGE COMMISSION**

**WASHINGTON, DC 20549**

# FORM 8-K

**CURRENT REPORT PURSUANT**

**TO SECTION 13 OR 15(D) OF THE**

**SECURITIES EXCHANGE ACT OF 1934**

Date of report (Date of earliest event reported) December 12, 2005

OGE ENERGY CORP.

(Exact Name of Registrant as Specified in Its Charter)

Oklahoma

(State or Other Jurisdiction of Incorporation)

| | |
|---|---|
| 1-12579 | 73-1481638 |
| (Commission File Number) | (IRS Employer Identification No.) |
| 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma | 73101-0321 |
| (Address of Principal Executive Offices) | (Zip Code) |

405-553-3000

(Registrant s Telephone Number, Including Area Code)

(Former Name or Former Address, if Changed Since Last Report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

---

**Item 8.01. Other Events**

OGE Energy Corp. (the Company ) is the parent company of Oklahoma Gas and Electric Company ( OG&E ), a regulated electric utility with approximately 744,000 customers in Oklahoma and western Arkansas, and Enogex Inc. and its subsidiaries, a natural gas pipeline business with principal operations in Oklahoma.

On December 13, 2005, the Company issued a press release announcing that OG&E received an order from the Oklahoma Corporation Commission ( OCC ) related to OG&E s May 20, 2005 request to increase its electric rates to pay for major reliability investments in OG&E s electric system and other costs. The OCC order provides for a $42.3 million increase in OG&E s electric rates and a 10.75 percent return on equity, based on a capital structure consisting of 55.7 percent equity and 44.3 percent debt. OG&E had requested an increase of approximately $89 million. The OCC order generally is consistent with the previously-reported Referee s recommendation. The new rates will go into effect in January 2006. For further information, see the press release attached as Exhibit 99.01 and a copy of the OCC order attached as Exhibit 99.02.

**Item 9.01. Financial Statements and Exhibits**

**(c) <u>Exhibits</u>**

| **Exhibit Number** | **Description** |
|---|---|
| 99.01 | Press release dated December 13, 2005, announcing Regulators order $42 million rate increase for OG&E. |
| 99.02 | Copy of OCC order dated December 12, 2005. |

---

**SIGNATURE**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**OGE ENERGY CORP.**
(Registrant)

By /s/ Scott Forbes
Scott Forbes
Controller

December 16, 2005

---

**Exhibit 99.01**

# Regulators order $42 million rate increase for OG&E

***Average residential electric bill to increase by about $3 per month***

OKLAHOMA CITY OG&E Electric Services said it is pleased the Oklahoma Corporation Commission has recognized the need for rate relief in ordering a $42.3 million increase, but noted the amount of the rate order will require OG&E to reduce planned electric system upgrades and expansion projects. OG&E has invested $600 million in such work since 2003 and will now consider when to return to the Commission to seek further rate relief.

OG&E sought an increase of $89 million to reflect the new, highly efficient McClain power plant, as well as increases in general business expenses and an ongoing program to replace aging poles, wires, transformers and related equipment. The Commission's Public Utility Division staff had proposed a rate increase of only $13 million and various intervenors in the case had proposed a rate reduction. The new rates are scheduled to go into effect in January.

We proposed reasonable funding of our investments that would keep our customers electric rates below the national and regional averages, said Steven E. Moore, Chairman, President and CEO of OGE Energy Corp. (NYSE: OGE), parent company of OG&E. In order to ensure the long-term reliability of our system, we will need to invest additional dollars and will need additional rate relief in the not-too-distant future."

The company said under the rate order, signed late Monday, small businesses will see a slight decrease in their monthly electric bills, but will not experience the level of reductions proposed by OG&E. OG&E also said the rate order includes an increase of about $3 per month for the average residential customer, while effectively lowering large industrial customers monthly bills. The new rate design, which was contrary to OG&E's proposal, was recommended by the Commission s Public Utility Division staff and intervenors in the rate case, including the state Attorney General and an industrial energy consumer group.

The rate order does include OG&E s proposals for new summertime assistance program for low-income customers, and a Guaranteed Flat Bill program that will enable residential customers the option to pay the same amount every month, and no rate increase for Tinker Air Force Base. The Commission s order also permits OG&E to earn a small return on under-recovered fuel expenses to help finance high fuel costs. This will benefit customers and the company by spreading the impact of high natural gas prices over a longer period of time.

OG&E serves about 744,000 customers in a service area spanning 30,000 square miles in Oklahoma and western Arkansas. OGE Energy also is the parent company of Enogex Inc., a natural gas pipeline business with principal operations in Oklahoma.

---

**Exhibit 99.02**

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF **OKLAHOMA GAS AND ELECTRIC COMPANY** FOR AN ORDER OF THE COMMISSION AUTHORIZING APPLICANT TO MODIFY ITS RATES, CHARGES, AND TARIFFS FOR RETAIL ELECTRIC SERVICE IN OKLAHOMA. | )<br>)<br>)<br>)<br>)<br>) | CAUSE NO. **PUD 200500151**<br><br>ORDER NO. |

| | |
|---|---|
| HEARING: | October 10 through October 24, 2005<br>Before the Commission *en banc* with Referee Jacqueline T. Miller |
| APPEARANCES: | David B. Dykeman and Andrew Tevington, Deputy General Counsels, James L. Myles, Assistant General Counsel and Annette P. Howlett, Legal Intern for Public Utility Division, Oklahoma Corporation Commission<br>William L. Humes and Elizabeth Ryan, Assistant Attorneys General, Office of Attorney General, State of Oklahoma<br>William J. Bullard, Robert D. Stewart, Jr., Clark Evans Downs, Dustin R. Fredrick, and Curtis M. Long Attorneys for Oklahoma Gas & Electric Company<br>Thomas P. Schroedter, James D. Satrom and J. Fred Gist, Attorneys for Oklahoma Industrial Energy Consumers<br>Ronald E. Stakem, Attorney for OG&E Shareholders Association<br>Cheryl A. Vaught and Scot A. Conner, Attorneys for Redbud Energy, LP<br>Kendall W. Parrish. Attorney for AES Shady Point, LLC<br>Shelton L. Benedict, Attorney for PowerSmith Cogeneration Project, LP<br>Rob F. Robertson and John M. Benson, Attorneys for ONEOK Gas Transportation, LLC<br>Rick D. Chamberlain, Attorney for Wal-Mart Stores East, LP<br>Karen White, Lieutenant Colonel, USAF, Air Force Utility Litigation Team for Federal Executive Agencies |

**FINAL ORDER**

**I. PROCEDURAL HISTORY**

On April 4, 2005, Oklahoma Gas and Electric Company (hereinafter referred to as Applicant , OG&E , or Company ) filed its Notice of Intent providing notice, pursuant to OAC 165:70-3-7, that it intended to file an application seeking to implement a plan which would modify the rates and charges for OG&E s Oklahoma jurisdictional customers. On April 8, 2005, the Oklahoma Industrial Energy Consumers ( OIEC ) filed its Motion to Intervene. The Attorney General of the State of Oklahoma ( AG ) filed his Entry of Appearance on April 28,

1

2005. The Commission issued **Order No. 504775** on May 2, 2005, granting the OIEC s Motion to Intervene.

OG&E filed its Application and supporting documentation on May 20, 2005, basing its request for a general rate change upon a test year ending December 31, 2004. OG&E proposed to implement the next phase of its Customer Savings and Reliability Plan and a general rate change of $89,064,720. Additionally, the Applicant requested to include the costs associated with the addition of the McClain generation facility in its rate base as described in the Joint Stipulation and Settlement Agreement in Cause No. PUD 200100455. Furthermore, the Applicant requested to implement enhanced reliability programs, to establish a separate recovery mechanism for major storm expense, to implement a fuel cost adjustment modification that includes service level assignment for line loss, to establish new rate classes for public schools and related facilities, a new Military Base Rider, a new low income assistance tariff, and a Custom Contract tariff. Moreover, the Applicant requested to make the Guarantee Flat Bill pilot tariff permanent and to modify the Green Power Wind Rider and Cogeneration Capacity Rider. Finally, the Applicant requested to adjust the power factor in the Power and Light and Large Power and Light rate classes, to reduce the subsidy of Residential customers by the small business class (General Service) by reapportioning the residential class subsidy, and to establish rate design to minimize inter-class and intra-class subsidy based on the cost of service and marginal cost study.

OG&E tendered with the filing of its Application, its complete Application Package pursuant to OAC 165:70-3-1, and concurrent with the filing of its Application Package, the Company provided to the Public Utility Division its Supplemental Application Package pursuant to OAC 165:70-5-20. Along with its Application, OG&E filed the Direct Testimony of Jack T. Coffman, Julie M. Cannell, Donald A. Murry, Ph.D., Susan D. Abbott, James R. Hatfield, John J. Reed, Donald R. Rowlett, Gene H. Wickes, John J. Spanos, John A. Jeter, Steven K. Holloway, Steve Goodner, Michael T. O Sheasy, Roger D. Walkingstick, P.E., and Dr. Laurence D. Kirsch.

On May 26, 2005, AES Shady Point, LLC ( AES ) filed its Motion to Intervene. On June 3, 2005, the OG&E Shareholders Association filed its Motion to Intervene. OG&E filed its Motion for Protective Order on June 7, 2005. The Commission issued **Order No. 506739** on June 13, 2005 granting AES Motion to Intervene. On June 13, 2005, the Public Utility Division of the Oklahoma Corporation Commission ( Staff ) filed its Response regarding Applicant s Compliance with the Minimum Filing Requirement notifying the Company that it is in substantial compliance with the minimum filing requirements as set forth in OAC 165:70. On June 14, 2005, OG&E filed its Objections to the AG s 2nd Set of Data Requests. On June 16, 2005, OG&E filed its Objections to the AG s 3rd Set of Data Requests. The Federal Executive Agencies ( FEA ) separately filed their Motion for Intervention and corresponding Certificate of Service on June 17, 2005. Additionally, Redbud Energy, LP ( Redbud ) filed its Motion to Intervene on June 17, 2005. On June 21, 2005, ONEOK Gas Transportation, LLC ( OGT ) filed its Special Appearance and Joinder in Certain Objections of OG&E to Certain Data Requests of the AG. OG&E filed its Objections to the OIEC s 2nd Set of Data Requests on June 23, 2005. On June 28, 2005, OG&E filed its Objections to the OIEC s 3rd Set of Data Requests. The Commission issued **Order No. 507566** on June 29, 2005, granting the OG&E Shareholders Association s Motion to Intervene. Additionally, OG&E filed its Objections to the OIEC s 5th Set of Data Requests on June 29, 2005. On June 30, 2005, OG&E filed its Objections to the

2

OIEC s 4th Set of Data Requests. The Commission issued **Order No. 507613** on June 30, 2005, granting OG&E s Motion for Protective Order.

The Commission issued **Order No. 507905** on July 6, 2005, granting the FEA s Motion to Intervene. Additionally, the Commission issued **Order No. 507906** on July 6, 2005, granting Redbud s Motion to Intervene. On July 7, 2005, OG&E filed its Objections to AES 1st Set of Data Requests. Calpine filed its Special Appearance concerning the Objections of OG&E to Certain Data Requests of the AG on July 8, 2005. On July 14, 2005, Staff filed its Motion to Establish Procedural Schedule. PowerSmith Cogeneration Project, LP ( PowerSmith ) separately filed its Motion to Intervene and Amended Certificate of Mailing on July 18, 2005. On July 18, 2005, Staff filed an Amended Notice of Hearing in regard to its Motion to Establish Procedural Schedule. OG&E separately filed its Objections to the OIEC s 6th Set of Data Requests and corresponding Amendment thereto on July 19, 2005. Additionally, OG&E separately filed its Objections to the OIEC s 7th, 8th, and 9th Sets of Data Requests on July 19, 2005. On July 22, 2005, OG&E filed its Objections to the OIEC s 10th Set of Data Requests. OGT separately filed its Second Special Appearance and Objection to Staff s Data Request PUD-69 to OG&E also on July 22, 2005. On July 29, 2005, OGT filed its Objection to Staff s Data Request PUD-90 to OG&E on July 29, 2005.

On August 1, 2005, OG&E filed its Objections to OIEC s 13th Set of Data Requests. Additionally, OG&E filed its Objection to the Response Time for OIEC s 11th, 12th, 13th, and 14th Sets of Data Requests on August 1, 2005. On August 9, 2005, OGT filed its Objection to the OIEC s 16th Set of Data Requests to OG&E. OG&E also filed its Objections to the OIEC s 16th Set of Data Requests on August 9, 2005. The Commission issued **Order No. 509506** on August 9, 2005, granting PowerSmith s Motion to Intervene. On August 11, 2005, OGT filed its Motion to Intervene. The Commission issued **Order No. 509833** on August 12, 2005, concerning the Motion for Procedural Schedule in regard to Cause No. PUD 200500151. OG&E filed its Motion for Admission of Counsel *Pro Hac Vice* on August 12, 2005. Additionally, Wal-Mart Stores East, LP ( Wal-Mart ) filed its Motion to Intervene on August 12, 2005. The Commission issued **Order No. 509835** on August 15, 2005, granting Calpine s Special Appearance. On August 17, 2005, OGT filed its Objections to PowerSmith s 2nd Set of Data Requests to OG&E. OG&E filed its Motion to Establish Notice Requirements on August 19, 2005. On August 24, 2005, OGT filed its Amended Notice of Hearing in regard to its Objections to PowerSmith s 2nd Set of Data Requests to OG&E. The Commission issued **Order No. 510369** on August 26, 2005, granting Wal-Mart s Motion to Intervene. The Commission issued **Order No. 510575** on August 31, 2005, in regard to OG&E s Notice of Hearing Direct Mail to Customers. The Commission issued **Order No. 510576** on August 31, 2005, granting OGT s Special Appearance and ruling on its Joinder in the Objections of OG&E to Certain Data Requests of the AG. The Commission issued **Order No. 510577** on August 31, 2005, in regard to OGT s Second Special Appearance and Objection to Staff s Data Request PUD-69 to OG&E. Additionally, the Commission issued **Order No. 510578** on August 31, 2005, in regard to OGT s Objection to Staff s Data Request PUD-90 to OG&E.

On September 1, 2005, the FEA filed its Motion for Temporary Admission of Out-of-State Attorney. Additionally, OG&E filed its Objections to AES 2nd Set of Data Requests on September 1, 2005. The Commission issued **Order No. 510744** on September 2, 2005, establishing OG&E s Publication Notice Requirements. The Commission issued **Order No.**



---

**510965** on September 8, 2005, in regard to OGT's Objections to PowerSmith's 2nd Set of Data Requests to OG&E. Additionally, the Commission issued **Order No. 510966** on September 8, 2005, in regard to OGT's Objections to the OIEC's 16th Set of Data Requests to OG&E. On September 8, 2005, several Parties filed their List of Major Issues or Issues List. These Parties included the AG, Staff, AES, the OIEC, Redbud, the OG&E Shareholders Association, Wal-Mart, and PowerSmith. PowerSmith also filed its Statement of Position on September 8, 2005. On September 12, 2005, OGT filed its Statement of Position.

Several Parties filed Responsive Testimonies on September 12, 2005. Redbud filed the Responsive Testimonies of Chad Wagner, Judah L. Rose (Redacted and Unredacted), and Kojo S. Ofori-Atta (Redacted and Unredacted). AES filed the Responsive Testimonies of Dr. Robert A. Durham, P.E. and Dr. Marcus O. Durham, P.E. Staff filed the Responsive Testimonies of Robert C. Thompson, CPA, Michael Read, CPA, Malini Gandhi, CPA, Crecetta L. Herbison, Edwin C. Farrar, CPA, Reema Malhotra, George Mathai, CPA, Helen Patel, Jason Thenmadathil, and Marvin Vaughn. Additionally, Staff filed its Accounting Exhibit on September 12, 2005. The OIEC filed the Responsive Testimonies of John S. Thornton, Daniel Peaco (Redacted and Unredacted), Glen E. Gregory, and Mark E. Garrett. Additionally, on September 12, 2005, the OIEC filed its Accounting Exhibits. Wal-Mart filed the Responsive Testimony of Jess Galura. The OG&E Shareholders Association filed the Responsive Testimony of John C. Dunn. The AG filed the Responsive Testimonies of J. Bertram Solomon and Scott Norwood. The FEA filed the Responsive Testimony of Robert J. Conner.

On September 13, 2005, the Referee filed her Oral Recommendation to Seal the Confidential Testimony of Daniel Peaco filed on September 12, 2005. The Commission issued **Order No. 511216** on September 15, 2005, granting OGT's Motion to Intervene. Additionally, the Commission issued **Order No. 511217** on September 15, 2005, granting the FEA Temporary Admission of Out-of-State Attorney. On September 16, 2005, OG&E filed its Motion to Strike the Responsive Testimony of Kojo S. Ofori-Atta. Redbud filed its Objections to OG&E's 1st Set of Data Requests on September 19, 2005. Redbud filed its Objections to OG&E's 2nd Set of Data Requests on September 20, 2005. On September 21, 2005, Redbud filed its Reply in Opposition to OG&E's Motion to Strike the Responsive Testimony of Kojo S. Ofori-Atta. AES filed its Objections to OG&E's 1st Set of Data Requests on September 21, 2005. On September 27, 2005, OG&E filed its Motion to Amend Procedural Schedule.

The Commission issued several Orders on September 29, 2005. The Commission issued **Order No. 511775** settling OG&E's Objections to the OIEC's 2nd Set of Data Requests. The Commission issued **Order No. 511776** settling OG&E's Objections to the OIEC's 5th Set of Data Requests. The Commission issued **Order No. 511777** settling OG&E's Objections to the OIEC's 4th Set of Data Requests. The Commission issued **Order No. 511778** settling OG&E's Objections to the OIEC's 6th Set of Data Requests. The Commission issued **Order No. 511779** settling OG&E's Objections to the OIEC's 8th Set of Data Requests. The Commission issued **Order No. 511780** settling OG&E's Objections to the OIEC's 10th Set of Data Requests. The Commission issued **Order No. 511781** settling OG&E's Objections to the OIEC's 9th Set of Data Requests. The Commission issued **Order No. 511782** settling OG&E's Objections to the OIEC's 7th Set of Data Requests.

Several Parties filed Rebuttal Testimonies on September 27, 2005. OG&E filed the Rebuttal Testimonies of Jack T. Coffman, Julie M. Cannell, Donald A. Murry, Ph.D., Susan D. Abbott, James R. Hatfield, John J. Reed, Donald R. Rowlett, Gene H. Wickes, John J. Spanos, John A. Jeter, Steven K. Holloway, Steve Goodner, Roger D. Walkingstick, P.E., Dr. Laurence D. Kirsch, Deborah Fleming, Rusty Whiteley, Jesse B. Langston (Redacted and Unredacted), Jeffrey E. Hyler, Bernard L. Uffelman, and Philip L. Crissup. The OIEC filed the Rebuttal Testimony of John S. Thornton, Daniel Peaco, Glen E. Gregory, and Mark E. Garrett. Additionally, the OIEC filed the Exhibits of John S. Thornton on September 29, 2005. Wal-Mart filed the Rebuttal Testimony of Jess Galura. Additionally, Wal-Mart filed Exhibit JPG-1 to the Rebuttal Testimony of Jess Galura. The AG filed the Rebuttal Testimony of Scott Norwood. The OG&E Shareholders Association filed the Rebuttal Testimony of John C. Dunn. Staff filed the Rebuttal Testimony of Edwin C. Farrar, CPA.

The Commission issued several Orders on September 30, 2005. The Commission issued **Order No. 512123** granting OG&E s Motion for Admission of Counsel *Pro Hac Vice*. The Commission issued **Order No. 512124** settling OG&E s Objections to AES s 2nd Set of Data Requests. The Commission issued **Order No. 512125** settling OG&E s Objections to the AG s 2nd Set of Data Requests. The Commission issued **Order No. 512126** settling OG&E s Objections to the AG s 3rd Set of Data Requests. The Commission issued **Order No. 512127** settling OG&E s Objections to the Response Time for OIEC s 11th, 12th, 13th, and 14th Sets of Data Requests. The Commission issued **Order No. 512128** settling OG&E s Objections to the OIEC s 13th Set of Data Requests. The Commission issued **Order No. 512129** settling OG&E s Objections to the OIEC s 16th Set of Data Requests. The Commission issued **Order No. 512130** settling OG&E s Objections to AES s 1st Set of Data Requests.

On September 30, 2005, OG&E filed its Verification of Compliance with Order No. 512123. Additionally, OG&E filed its Affidavit of Publication from the *Oklahoman* on September 30, 2005. The Commission issued **Order No. 512209** on October 3, 2005, granting OG&E s Motion to Amend Procedural Schedule. Additionally, the Commission issued **Order No. 512210** on October 3, 2005, settling OG&E s Objections to the OIEC s 3rd Set of Data Requests. On October 3, 2005, Staff filed a Revision to the Responsive Testimony of George Mathai filed on September 12, 2005. On October 4, 2005, OG&E filed its Supplement to the Rebuttal Testimony of Bernard L. Uffelman. Additionally, OG&E filed its Affidavit of Mailing in regard to its Special Notice bill insert on October 4, 2005. Several Parties filed their Exhibit List or Witness and Exhibit List on October 5, 2005. These Parties included OG&E, the AG, Staff, Redbud, the OG&E Shareholders Association, OGT, Wal-Mart, the OIEC, and AES.

Several Parties filed Testimony Summaries on October 5, 2005. OG&E filed the Testimony Summaries of Jack T. Coffman, Julie M. Cannell, Donald A. Murry, Ph.D., Susan D. Abbott, James R. Hatfield, John J. Reed, Donald R. Rowlett, Gene H. Wickes, John J. Spanos, John A. Jeter, Steven K. Holloway, Steve Goodner, Michael T. O Sheasy, Roger D. Walkingstick, P.E., Dr. Laurence D. Kirsch, Deborah Fleming, Rusty Whiteley, Jesse B. Langston, Jeffrey E. Hyler, Bernard L. Uffelman, and Philip L. Crissup. The AG filed the Testimony Summaries of J. Bertram Solomon and Scott Norwood. Staff filed the Testimony Summaries of Robert C. Thompson, CPA, Michael Read, CPA, Malini Gandhi, CPA, Crecetta L. Herbison, Edwin C. Farrar, CPA, Reema Malhotra, George Mathai, CPA, Helen Patel, Jason Thenmadathil, and Marvin Vaughn. Wal-Mart Filed the Testimony Summary of Jess Galura.



The OG&E Shareholders Association filed the Testimony Summary of John C. Dunn. The OIEC filed the Testimony Summaries of John S. Thornton, Daniel Peaco, Glen E. Gregory, and Mark E. Garrett. Redbud filed its Summary of the Responsive Testimony including Chad

Wagner, Judah L. Rose, and Kojo S. Ofori-Atta. AES filed the Testimony Summaries of Dr. Robert A. Durham, P.E. and Dr. Marcus O. Durham, P.E. The FEA filed the Testimony Summary of Robert J. Conner.

The Commission issued **Order No. 512560** on October 6, 2005, granting the FEA Admission of Out-of-State Attorney. The Commission issued **Order No. 512561** on October 6, 2005, settling Redbud s Objections to OG&E s 1st and 2nd Sets of Data Requests. Additionally, the Commission issued **Order No. 521562** on October 6, 2005, settling AES Objections to OG&E s 1st Set of Data Requests. On October 7, 2005, Curtis M. Long filed his Entry of Appearance on behalf of OG&E. The Commission issued **Order No. 512801** on October 10, 2005, denying OG&E s Motion to Strike the Responsive Testimony of Kojo S. Ofori-Atta.

The Staff has filed all Public Comments accumulated to date. Additionally, at the Hearing of the Merits, time was allotted daily for citizens to make public comment, and certain citizens did make such public comment on the record. The Hearing on the Merits for this Cause commenced pursuant to the Notice of Hearing on October 10, 2005, and concluded on October 24, 2005. On October 20, 2005, the Attorney General's Office, the OIEC, the Staff and Wal-Mart filed a Joint Stipulation and Settlement Agreement on Rate Design. The Federal Executive Agency concurred with the Stipulation as to the treatment of the Military Base Rider (MBR).

**II. TESTIMONY SUMMARIES**

**OKLAHOMA GAS AND ELECTRIC COMPANY**

**Susan D. Abbott**

OG&E s current senior unsecured ratings of A2 from Moody s and AA- from Fitch, respectively, and the issuer rating of BBB+ from S&P are predicated on stable and consistent levels of cash flow, and what is considered to be a responsive and constructive approach to regulation in Oklahoma. The ratings are supported by financial metrics consistent with guidelines followed by the agencies for the current rating categories as well as comparison to other utilities in similar lines of business.

Rating agencies and investors are increasingly focused on the outcome of regulatory activities after a hiatus from rate activity for, in some cases, a decade. S&P has recently written regulatory risk has always been a key component...of investor utilities creditworthiness. Decisions by public service commissions can profoundly affect utilities credit quality. Further, S&P gave OG&E a negative outlook in the face of its rate case in 2002 to reflect, the uncertainty associated with the outcome of the rate case... Indeed, when the case was settled, Moody s reduced OG&E s rating citing the negative effects of OG&E s rate cut and regulatory risks related to a rate filing expected later this year.

6

While all three rating agencies are comfortable with their ratings on OG&E, it is quite clear that adverse regulatory activity resulting in a diminution of the financial performance that supports the current ratings, particularly as measured by cash flow relative to debt obligations, could negatively impact those ratings. S&P stated earlier this year that OG&E s stable outlook is in part predicated on the utility receiving a favorable outcome in its upcoming rate case to be filed in 2005. In Moody s October, 2004 write-up on OG&E, that agency stated that an important factor that could lead to a downgrade is an adverse regulatory environment that results in under-recovery of costs that places considerable pressure on financial measures .

Because S&P carries an A-2 rating on OG&E s commercial paper, the Company s ability to access the short-term market could be in jeopardy if the rating fell. The A-3 market, one rating category below the Company s current rating, is often illiquid, and the A-2 commercial paper market becomes quite illiquid at times, especially during times of turmoil and the end of the calendar year.

Each rating agency has a unique methodology for determining ratings, but a combination of an assessment of financial condition relative to business risk is a common theme for all three major agencies. As a result, while financial metrics, cash flow measurements in particular, are extremely important, they are not the only measures used. At the same time, ratings are not a technical exercise, but the product of a combination of financial analysis, judgment and accumulated experience. Being able to know with any precision what the rating agencies will do is impossible. But, having worked for Moody s for 20 years, and having used all the agencies services for another 10 gives me a profoundly well-hone understanding of how they *are likely* to act. Were a regulatory decision to be made containing elements such as the Holding Company capital structure as the basis of OG&E s allowed return, short term interest rates applied to long term assets, and comparisons with averages without a proper analysis of what those averages contained, it is likely that the rating agencies would react negatively to such a decision.

The influence ratings have on the financial condition and business environment of companies they rate is important and should not be ignored. While it is not the only factor a regulatory body should be concerned with, being inattentive to the potential outcome, and what that means to the company and all its constituents, is short-sighted at best. The requested rate increase will produce financial metrics within the range necessary to maintain its current ratings, and should therefore be granted.

**Jack T. Coffman**

In my Direct Testimony I explained the process by which OG&E determined that purchasing an existing generation facility was in the best interests of the Company and its customers. This decision was based on the desire to replace existing purchase power contracts and provide savings to OG&E s customers in the process. I explained why replacing existing purchase power contracts with new purchase power agreements would expose the Company and its customers to an unacceptable level of risk in today s market, and I explained that construction of new facilities could not be accomplished in a timely manner to replace existing contracts and accommodate load growth on the OG&E system. I also explained that the long-term capacity purchase option was considered and rejected based on reliability and cost considerations. I explained the selection process used to examine existing power plant purchase options, and I described the negotiation process utilized by the Company to secure the best price for the best plant at the most favorable location to meet the needs of the customers. I explained why OG&E chose private negotiations rather than competitive bidding to secure the most favorable price for the acquisition of existing generation. My Exhibit__JTC-7 attached to my Direct Testimony demonstrates that the price per kilowatt paid by OG&E for the McClain Plant is a fair, just, and reasonable price for the facilities acquired, is less than the original construction cost, is less than the cost OG&E would have incurred to build a comparable facility, and is less than the price OMPA paid for its interest in the same facility. I also explained how the McClain facility receives its fuel supply through a combination of transportation and storage services from OGT and Enogex. I also discussed the LTSA with General Electric to maintain and service the McClain Facility.

In my Rebuttal Testimony I challenged two Staff adjustments proposing a significant reduction to the Company s production plant O&M expenses. Staff arrives at its adjustments by taking a simple 3-year average of three of OG&E s actual production plant O&M FERC Accounts to develop the largest possible total adjustment. Staff s adjustments fail to take into account the effects of inflation which has been significant during the three-year simple average period it used, and Staff s adjustments to production plant O&M expense includes a labor adjustment. Including a labor adjustment as a component of Staff s proposed adjustments to production plant O&M results in a double-dip because Staff has already proposed adjustments to OG&E s labor expenses. If Staff had recognized inflation in making its recommendation, and if Staff had appropriately recognized OG&E s labor costs without double-counting, Staff s recommendation would have been to increase OG&E s pro forma test year production plant O&M expenses by $ 3,521,022.

**Deborah Fleming**

In my rebuttal testimony, I responded to two issues raised by Staff and intervenors. The first is the contention of the Staff, the Attorney General and OIEC that certain elements of OG&E s rate base should be regarded as being entirely funded with debt. These parties argue that the return OG&E should be allowed to earn on those rate base elements should be calculated at rates lower than OG&E s overall cost of permanent capital. These contentions are incorrect and the proposal to treat certain of OG&E s non-plant investments as financed through short-term debt is without merit and inconsistent with well-settled principles of financial management. Additionally, the attribution of debt financing to these rate base elements could actually harm OG&E s ratepayers.

The second issue addressed is the assertion by OIEC witness Thornton and AG witness Soloman that OG&E s rates should be based on the capital structure of OGE Energy. The use of the OG&E s independent capital structure, rather than the capital structure of OG&E s parent, is appropriate and consistent with well-established ratemaking principles.

Mr. Norwood s rationale for removing the McClain regulatory asset from rate base and treating the McClain regulatory asset as if it had been funded with short-term debt is arbitrary and should be rejected.

Mathai s and Garrett s claim that OG&E finances non-plant investments using short-term debt is incorrect. OG&E does not finance non-plant investments (such as pre-paid pensions, the McClain asset, materials and supplies, fuel inventories, and gas in storage balances) using short-term debt. These items are permanent elements of OG&E s balance sheet. Using short-term debt to fund these utility assets would not be prudent financial management and could place OG&E in severe financial distress. Such proposals reflect a misunderstanding of the way in which OG&E uses its short-term borrowing facilities. If OG&E actually used its short-term borrowing capacity in the manner proposed by Staff and OIEC, OG&E could easily find itself in a liquidity crunch, which would result in even higher debt costs for OG&E and its ratepayers.

The use of short-term debt to finance selected rate base items is inconsistent with established financial principles that strongly advise against using short-term debt to finance permanent assets. Just because OG&E has access to short-term debt does not mean that it is a sound financial practice for OG&E to use its short-term borrowing ability to finance these permanent investments in utility assets. The rating agencies demand that investment grade companies maintain financial flexibility, which includes large available amounts of short-term liquidity.

It is absolutely inappropriate for OIEC witness Thornton and AG witness Soloman to base OG&E s rates on the capital structure of OG&E s non-utility parent. OG&E has its own separate capital structure, credit ratings, long-term debt, bond investors, and credit facilities. Mr. Thornton s use of the consolidated capital structure to set rates for OG&E would be entirely at odds with the reality that investors view OG&E as a distinct entity from OGE Energy.

In the post-Enron marketplace, rating agencies take an extremely stringent view in how they analyze a utility s balance sheet for purposes of calculating financial metrics. Today, the agencies require utilities to impute debt and associated interest for power purchase agreements, leases, and contingent obligations. This treatment of long-term obligations as additional debt requires utilities to maintain higher equity ratios in order to maintain a balanced capital structure. As a result, while OG&E s equity ratio may seem high by standards of the past, thicker equity ratios are needed to maintain strong bond ratings and the lower cost of borrowing that goes with them.

**James R. Hatfield**

In my Direct Testimony, I advise the Commission that I serve as OG&E s overall policy witness. I address the Company s need for a rate increase, and I describe the Company s *Customer Savings and Reliability Plan*. I provide an update regarding the $75 million phased-in customer savings established by the 2002 Settlement Agreement, and I discuss the rate of return OG&E is requesting in this proceeding. I advise the Commission that this case is about reliability and the investment required to maintain safe and reliable service or existing customers as well as those future customers created by economic growth in our service area. The Company s ability to ensure long-term reliability and pass along future savings to customers depends on our ability to adequately recover these investments. OG&E is requesting the Commission approve a rate increase of $89,064,720 to recover its costs related to providing reliable service. I discuss OG&E s goals related to rate design and customer impacts associated with its revenue requirement, particularly with respect to residential and small business

9

customers and the need to eliminate current subsidies currently being received by the large industrial customer class. Acquiring the McClain plant was the first step in OG&E s *Customer Savings and Reliability Plan* to proactively invest in reliability improvements and provide long-term savings to customers. I also describe OG&E s steps to improve its aging infrastructure by proactively managing its infrastructure by analyzing and addressing those areas of the system where the benefits of new investment can be maximized rather than simply reacting to customer outages. During 2004, OG&E invested $235 million in capital infrastructure improvements, not counting the McClain acquisition; during 2005, OG&E planned to invest an additional $250 million. I advise the Commission that OG&E is not alone in facing the aging infrastructure issue; this is an issue affecting the U.S. electric industry as a whole. In this proceeding, OG&E asks the Commission to allow the Company to recover the cost of the highly efficient McClain plant, to recover the cost of dramatically increased system reliability investments, and to recover the increasing business costs that OG&E has been experiencing. In the third section of my Direct Testimony I describe the regulatory risks and investor expectations resulting from OG&E s implementation of the Settlement Agreement. As a result of those expectations, I advise the Commission that anything less than a return consistent with the 2002 Settlement Agreement would inadequately compensate OG&E for the risk it assumed in the 2002 Settlement Agreement while customers are already experiencing the savings. I point out that even given the expectation of an 11.55% Return on Equity applied to 56% common equity, OG&E s debt rating was downgraded by two of the major rating agencies. From Wall Street s perspective, OG&E s credit rating remains subject to the Commission granting a timely and sufficient rate increase to cover the Company s investments in reliability and remain financially healthy. As I state in my testimony, Dr. Murry recommends a return on equity of 11.75% in his testimony as the appropriate level for this cause. I also describe the substantial increases OG&E has experienced in O&M expenses particularly as they relate to higher medical costs, labor costs and higher funding levels for employee benefits. In this proceeding, OG&E is requesting a total company O&M Expense level of $305,878,227; Chart 7 in my testimony summarizes the major categories of the Company s pro forma O&M adjustments.

In my Rebuttal Testimony, I advise the Commission that OG&E was very disappointed but, sadly, not surprised with the irresponsible proposals of the OIEC and the AG. Their recommendations are not in the public interest, are short-sighted, would jeopardize the long-term reliability of the electric system, and would significantly impair the financial health of OG&E. The consultants retained by the Attorney General and the OIEC have filed disingenuous recommendations that should be rejected by the Commission. Their recommendations, if adopted, would make it all but impossible for OG&E to maintain, much less enhance, electric reliability in the state. In my Rebuttal Testimony I remind the Commission that the OIEC has intervened in OG&E s rate proceedings for the past decade or so. Historically, the OIEC proposals have been extreme, focusing only on short-term benefits to the largest industrial customers without regard to any long-term consequences. The AG s recommendation would jeopardize the future reliability of OG&E s electric system, would impair the Company s ability to access capital markets, destroy any perception of regulatory fairness in Oklahoma and damage Oklahoma s business climate. The recommendations of the OIEC and the AG are not in the public interest and should be ignored by the Commission. Staff s recommendation of a $13.1 million rate increase, when adjusted to eliminate non-traditional adjustments and unfounded positions, would result in a Staff minimum recommendation of $50.5 million, as shown on my rebuttal Schedule JRH 2R. Thus, the minimum increase the Commission should consider is in

10

excess of $50.5 million. The level of O&M Expense recognized by the Commission is critical in establishing OG&E s rates in this proceeding. Parties are recommending significant decreases to the Company s test year expenses in this case while simultaneously ignoring that fact that OG&E s costs are increasing. These unrealistic recommendations for O&M Expense, if accepted, would negatively impact reliable electric service. OG&E has worked very hard to live up to its part of the bargain in the 2002 Settlement Agreement; we trust the Commission will look at all the issues and appropriately compensate the Company for its efforts.

**Jeffrey E. Hyler**

OGE Energy delivers total compensation to employees through two major components -- base salary and annual incentive.

Towers Perrin was asked to analyze the prevalence of annual incentives at 24 similar electric and gas utilities, and compare OGE Energy s levels of annual incentives and total cash compensation to these peers.

In our prevalence analysis, Towers Perrin found that all of the 24 electric and gas utility peer companies maintain a formal annual incentive plan. In addition, the vast majority of individual positions (92% of all employees) are typically eligible for annual incentives through these plans. Therefore, we established that it is standard practice in the electric and gas utility industry to maintain an annual incentive plan.

We then performed analyses to assess: (1) whether OGE Energy s total cash compensation levels could remain competitive without the Company s annual incentive plan; (2) whether the annual incentive levels used by OGE Energy were in line with market levels; and (3) whether OGE Energy s total cash compensation, including annual incentives, is competitive with market levels.

To test whether OGE Energy could remain competitive without the annual incentive component, Towers Perrin conducted a quantitative assessment of OGE Energy s pay levels to market levels both including and excluding the annual incentive component.

Our competitive findings showed that without an annual incentive plan, OGE Energy s base salaries would trail total cash compensation (base salary plus annual incentive) levels provided by the market by 12-13%. Additionally, we found that OGE Energy s annual incentives were in line with market practice. Finally, after adding annual incentives, OGE Energy s total cash compensation (target and actual) is competitive with, or slightly below market when compared to the peer group.

Rather than provide annual incentive opportunities to employees, OGE Energy could raise its base salary levels to market levels to stay competitive on a cash compensation basis; however, it would result in a higher level of fixed cost. Moreover, paying compensation solely in salary could remove incentives for employees to provide superior service to customers and the other constituencies that OGE Energy serves. Annual incentives ensure that individuals have an element of at risk compensation that allows OGE Energy to differentiate pay based on performance and direct compensation to those employees that are most deserving.

11

**Jesse B. Langston**

In my Rebuttal Testimony I addressed issues raised by the OIEC, the AG, and other intervenors related to OG&E s need for capacity and the process used by the Company as it considered alternatives available that would satisfy the commitments made by OG&E in the Settlement Agreement. As the OG&E manager responsible for the execution and day to day leadership regarding this process, I served as the lead negotiator in discussions and negotiation sessions with counterparties, and I provided oral briefings on a regular basis to executive management concerning those negotiations. The OIEC s witness, Mr. Peaco, concludes erroneously that OG&E s capacity margins are imprudent, that the Company s treatment of the PowerSmith contract was inappropriate, and suggests that OG&E s recovery of McClain costs should be benchmarked against transactions from 2004 in power pools significantly removed from the SPP, using 20/20 hindsight. He reaches his unfounded conclusions by ignoring the Direct Testimony filed by OG&E in support of its case. I advised the Commission that the SPP s minimum capacity margin is just that the minimum level SPP s utility members are required to maintain, and I point to a Commission decision recognizing that reserve levels above that level are appropriate. I remind the Commission that OG&E s obligation in the Settlement Agreement was to provide its customers with $75 million in savings, and the OIEC s witness misses the boat when he suggests OG&E acted imprudently by having capacity margins above the SPP minimum requirement. The OIEC witness suggests OG&E should have reassessed its decision to purchase McClain after the December 18, 2003, FERC Order was issued. I advised the Commission that throughout the period from December 18, 2003, through July 8, 2004, when OG&E closed on the transaction, we continued to look at the conditions in the market, the price OG&E would pay for McClain, and at other options that might be available. During that period nothing changed to suggest that OG&E should not move forward with the McClain acquisition.

The AG s witness, Mr. Norwood, criticizes OG&E for failing to document that portion of its process relating to negotiations with SPS. Regrettably, I did not do so at the time; I document those discussions in my Rebuttal Testimony. In short, SPS did not have capacity to sell after 2004 and approached OG&E to purchase capacity in 2004 and 2005. With that documentation, there is no justification for Mr. Norwood s proposed penalty.

Witnesses testifying for the Intervenor, Redbud, seek to relitigate the FERC s decision granting OG&E authority to close on the McClain transaction. Mr. Wagner claims incorrectly that OG&E never offered to purchase a portion of the Redbud facility; I refute that claim in my testimony and advise where and when that offer was made. Mr. Rose attempts to compare the McClain acquisition to unsolicited offers, first by mischaracterizing Mr. Coffman s Exhibit__JTC 1, then, by making a series of cost misallocations, which when corrected, demonstrate once again that the McClain acquisition was better for the Company and its customers. Witnesses testifying for the Intervenor, AES, also attempt to relitigate the FERC decision accepting OG&E s contested settlement offer and granting OG&E authority to close on the McClain transaction.

12

---

**Michael T. O Sheasy**

The purpose of my testimony and participation in this proceeding is to support the filing on a permanent basis by Oklahoma Gas & Electric (OG&E) of its Guaranteed Flat Bill (GFB) program. This support includes: 1) sharing my direct experience with the adoption and implementation of fixed bill products which has been filed in this case by OG&E as the Guaranteed Flat Bill (GFB), 2) describing how the GFB offers will be computed initially if the GFB application is approved by this Commission, and 3) discussing how future GFB offers will be computed.

The fixed bill product charges a participating customer a constant total monthly dollar amount for the contract year. Unlike budget or average billing programs, there is no true-up. This voluntary bill offer will be based upon each individual customer s own expected usage. This expected usage will be projected by considering a weather-normal year and changes in usage resulting from the customer moving from the standard tariff to GFB. This expected usage will be run through the standard tariff and a risk premium will be added to cover the additional risk which the customer migrating to GFB will add to OG&E.

This is the same fixed bill billing methodology used by nearly every electric utility currently offering fixed bill. It is a sound and cost-based methodology. The experiences of OG&E s pilot GFB program are considered in this design.

This addition to OG&E s pricing options will add value for participants by enabling them to know their electricity bill with complete assurance, and by providing a significant addition to their product alternatives. GFB will also protect and help non-participants by the modest and profitable growth which will ensue from GFB participants, and it will improve OG&E s customer satisfaction. I encourage this Commission to grant its approval.

**Donald R. Rowlett**

The purpose of my testimony is to explain the calculation of OG&E s requested general rate change. In that regard, I sponsor the Company s financial statements and schedules included in Sections B, C, D, E, H, I, J, and K of the Company s Application Package. OG&E is requesting a general rate change pursuant to Chapter 70, Minimum Standard Filing Requirements, of the Commission Rules. The accounting exhibits, schedules, testimony and evidence that support the general rate change are included in the Application Package filed in this cause. OG&E complied with the notice requirements contained in Chapter 70 on April 4, 2005, and on May 20, 2005, the Company filed its application seeking to modify its rates and charges for its Oklahoma jurisdiction customers through a rate increase of $89,064,720, effective with the first billing cycle in December 2005. OG&E s exhibits were based on the financial results of the test year ended December 31, 2004. The Application Package contains eleven pro forma adjustments to rate base and twenty-seven pro forma adjustments to operating income. In my testimony I explain the purpose of pro forma adjustments, and I explain the general categories of pro forma adjustments. Chart 1 of my Direct Testimony summarizes the calculation of OG&E s requested rate increase, and I describe and explain the components used to determine the values stated on each line on Chart 1 for the rate change calculation. In Section III of my testimony I describe the pro forma adjustments to rate base which I sponsor, and I

13

explain the Holding Company asset allocation. In Section IV of my testimony I sponsor pro forma adjustments 10 through 22, 25, 26, and 27 to the Company s Operating Income Statement, and I describe each of those adjustments. I also propose to normalize storm expense associated with minor storms and a recovery mechanism for expenses related to major storms through a Major Storm Expense Rider.

In my Rebuttal Testimony I cover a number of accounting adjustments proposed by various Staff witnesses, by Mr. Mark E. Garrett for the OIEC, and by Mr. Scott Norwood for the AG. As a general matter, my testimony addresses novel, unconventional and inconsistent approaches utilized by these witnesses where sound accounting principles and regulatory policies, and consistent application of those principles and policies, should be the norm. In many cases the underlying facts are ignored and an unsupported methodology is proposed. The approaches these witnesses take have one thing in common: their adjustments are designed to eliminate cost recovery and return on investment. The specific areas where Staff, the AG and the OIEC have departed from sound accounting principles and have deviated from consistent application of those principles are: Construction Work in Progress, Prepaid Pension Benefit Obligation, treatment of the McClain Regulatory Asset, Employee Retirement 401K Match, Gain on Sale of Assets, Storm Damage Expense, Payroll Adjustments, Bad Debt Expense, Prepayments for EEI Dues and Economic Development Memberships, the Commission Assessment, Materials and Supplies Inventory, Advertising and Marketing, Legislative Expenses, Research and Development, and Outside Services and Legal Expense. For each of these areas I provide detailed explanations concerning the inappropriateness of the adjustments proposed, variously, by Staff, the AG, and the OIEC, and I have indicated specific errors these parties have made in the calculation of their proposed adjustments. For example, Staff, the AG, and the OIEC all recommend updating balances for plant in service and accumulated depreciation to June 30, 2005, in their respective approaches to Construction Work in Progress ( CWIP ) for projects completed within six months of the end of the test year. Mr. Garrett failed to include $45,514,258 of CWIP which are projects completed, and serving customers but not yet transferred on the books, in his updated plant in service at June 30, 2005, and Mr. Norwood makes a $7 million error in his calculation that understates even the plant in service balance at June 30, 2005. My Rebuttal Testimony describes the errors contained in the adjustments proposed by Staff, the AG, and the OIEC and explains the corrected adjustment in detail, to the extent the adjustment is appropriate given the applicable accounting principles and appropriate regulatory methodology. With respect to Outside Services and Legal Expense, Staff is correct in recommending an adjustment of $254,543 for legal fees in Arkansas; OG&E s pro forma expense should be reduced by this amount. Conversely, Mr. Garrett gives no justification for his adjustment to Outside Services and Legal Expense other than to observe that the test year expenses are higher than in past years.

**Bernard L. Uffelman**

OG&E s use of the Distrigas formula to allocate corporate overhead costs to OG&E and its other regulated and non-regulated affiliates is appropriate. The Distrigas method, which is based on an equal weighting of gross plant, net revenues and payroll has been widely recognized and approved by regulators, not only for financial reporting purposes but also for regulatory purposes, for allocating corporate support service costs to business segments. This approach is also consistent with the Cost Accounting Standards Board s Cost Accounting Standards use of a

14

---

three-factor formula consisting of payroll dollars, operating revenue and capital assets for allocating residual costs such as corporate overheads because It takes into account three broad areas of management concern: The employees of the organization, the business volume, and the capital invested in the organization.

The three-factor formulas proposed by Messrs. Mathai, Norwood and Garrett totally ignore OG&E s labor costs and overweight revenues for the sole purpose of artificially reducing the allocation of OG&E s corporate overhead costs to OG&E. Their methods are not reflective of the areas of concern and focus of OG&E s management because they double count revenues and totally ignore labor costs. The three factors that comprise the Distrigas method (i.e., net revenues, gross plant, and payroll), in addition to being attuned to the factors that cause corporate support service charges to be incurred, are independent enough of each other that no over-weighting of any one aspect of operations occurs.

Adoption of the three-factor formulas proposed by Messrs. Mathai, Norwood and Garrett will produce distorted and widely fluctuating results as evidenced by the results of their own proposals in this proceeding. Even though they all claim to have adopted Staff s allocation methodology as presented in the recent Oklahoma Natural Gas Company case, their three different proposed reductions to OG&E s allocated costs in this case range from $2.3 million to $7.5 million. The continued and consistent use of the Distrigas formula to allocate corporate overhead costs to OG&E serves to minimize such distortions and fluctuations. These witnesses have failed to show that modification to the Distrigas formula is just and reasonable under the circumstances and therefore their proposed methods should be rejected by the Commission.

Continued use of the Distrigas three-factor formula based on net revenues, gross plant and labor ratios is appropriate for allocating OG&E s corporate overhead costs and prevents cross-subsidies between regulated and non-regulated business units. The Distrigas method has received sufficient record support through commission regulatory scrutiny and approval over the years to be used by utilities, including OG&E, as an acceptable method for allocating corporate support service costs. Consistent use and application of the Distrigas method also eliminates the need for the Commission to constantly address the cost allocation issue in each OG&E rate proceeding and deliberate as to which cherry picked allocation factors are being presented this time around in an attempt to allocate corporate overhead costs away from OG&E. Consistent use and application of the Distrigas method also eliminates the possibility of having to allocate and account for corporate overhead costs differently by jurisdiction depending on which variation of the allocation methodology was approved for use in each jurisdiction.

In summary, I recommend that the Commission reject the three very different allocation methods proposed by Messrs. Mathai, Norwood and Garrett and approve the continued use of the Distrigas method by OGE for allocating corporate overhead costs to the various OGE business segments including OG&E.

**Rusty Whiteley**

Staff s recommendation of an adjustment to depreciation expense for the McClain Regulatory Asset based on Staff s adjustment to the depreciation rate for Prime Movers is fundamentally in error. The lives of the asset components of the McClain plant are determined

15

---

based on the recommendations of the manufacturer and the services set out in the LTSA are designed primarily to assure reliability for the plant based on the expected lives of its component parts. LTSA services do not enhance the expected lives of the components of the plant. Instead the expected lives of the plant s asset components determine the service that must be provided by the LTSA. The LTSA insures reliability benefits for the McClain plant by providing equipment, technical support, knowledge and experience, as well as a preferential priority for parts and services. The LTSA is a particularly good idea now due to the lack of historical experience with the technology and key replacement parts with a proven runtime history have been difficult to secure from sources other than GE. Additionally, the LTSA provides for these parts on a discounted basis.

The new technology and combined cycle configuration increases efficiency and megawatt output over gas-fired plants and even over other gas turbine facilities resulting in fuel savings thus benefiting ratepayers. It is beneficial to maintain the LTSA with GE because GE is the manufacturer of the components of McClain. Thus, GE is able to provide to us a unique expertise on plant component lives that is valuable for determining our scheduling for inspections, overhaul, maintenance and replacement of parts. OG&E does not rely on the LTSA to establish the lives of the components of the McClain facility. OG&E determined lives of the asset components of the McClain facility using input from several sources including actual industry experience from GE and OG&E s own experience with various components.

OG&E cannot generally compare the component parts at the McClain facility with its experience in useful lives of components at its other plants because the McClain facility utilizes new technology that is operated differently and OG&E simply does not have the extensive historical data to draw definitive conclusions. Therefore, it is not possible to make a valuable comparison between McClain and other OG&E units. Market conditions will also affect the useful lives of your plant assets.

Maintenance and replacement is based on plant operations, which includes both factored starts and factored hours of operation. Staff is incorrect to conclude that OG&E assigned depreciable lives based on frequent maintenance of the plant under the LTSA. The lives of the component parts of the McClain facility are determined by manufacturer s recommendations and industry experience. The schedule of services in the LTSA is keyed to the anticipated lives of those components, not vice versa. The LTSA does not determine the appropriate plant lives in any way for the plant lives would be shorter without maintenance and replacement such as provided by the LTSA. The LTSA does not extend the plant s useful life; it ensures that its useful life can be achieved.

Staff s recommendation of a 40 year life for the Prime Movers is entirely arbitrary. A 40 year life for these assets has no operational, technical or engineering basis and is contrary to GE recommendations and industry experience for these components.

Mr. Garrett s recommendation to reduce the depreciation expense for the McClain facility is simply arbitrary and utterly without support. Mr. Garrett has no expertise with the operational, technical and engineering requirements for this plant, and he makes no effort to justify his recommendation. Additionally, Mr. Garrett invalidly compares his recommended service life for McClain with other gas-fired plants in OG&E s fleet of plants because the service



---

life of components of the McClain facility cannot be validly compared to those of OG&E s other gas-fired plants.

**Julie M. Cannell**

My testimony discusses the probable impact of the outcome of this Oklahoma Gas and Electric Company s rate proceeding on equity investors evaluation of the Company.

Credit rating agencies Moody s Investors Service and Standard & Poor s consider OG&E to be financially stable and hence a good credit risk. Their assessment is based, in part, on Oklahoma s constructive regulatory environment. However, the rating agencies share a concern that the state s regulatory climate may change, which might result in a downgrade of the Company s debt ratings. In turn, a downgrade would make it more expensive for OG&E to raise money in the capital markets to continue its program of infrastructure renewal.

Institutional investors Merrill Lynch, A.G. Edwards, and Lehman Brothers also have an acute awareness of this rate proceeding. The analysts as well as Value Line recognize that the return on equity the Commission allows OG&E the opportunity to earn will be a key factor in the Company s financial health going forward. Institutional investors currently consider the Oklahoma regulatory climate to be responsible and constructive. They understand that regulation must be balanced to protect the interests of both investors and consumers.

Investors now require a higher return for investing in electric utility commons stocks to balance the increased risk of investing born of deregulation, increased competition, fuel cost increases and technological change. Even with the changes that have taken place in the industry, electric utility investors continue to seek companies that can offer stable earnings and regular dividends. As a result, these investors place a high value on consistent and constructive regulation.

Institutional investors and hedge funds have grown dramatically in the amount of capital they control. This growth has had a significant impact on the speed with which the market reacts to unfavorable developments. Institutional investors are important to OG&E and OGE Energy because of the sheer size of their investment positions. Hedge funds are well known for trading in information and taking actions that are event-driven. Both institutional investors and hedge funds are monitoring the current rate case based on their assumptions about its outcome and the implications for the quality of Oklahoma regulation, and could take investment action in the securities of OG&E and OGE Energy if their expectations are not realized.

I believe that the investment community would find an 11.75% ROE reasonable for OG&E. That level of return on equity would be seen as a positive signal that constructive regulation is being carried forward in Oklahoma. It is within the range of assumptions stated in analyst reports that reflect investor expectations. An 11.75% ROE would also result in a lower cost of new debt capital that would eventually be reflected in customer rates.



---

**Philip L. Crissup**

Redbud and AES were granted intervenor status in this proceeding as customers of OG&E. Redbud is an independent power producer ( IPP ), and AES is a QF with a Commission-approved PURPA contract with OG&E. In my Rebuttal Testimony I advise the Commission that on September 12, 2005, these intervenors filed testimony by their respective witnesses addressing issues that were previously addressed and resolved by the FERC in its Order issued on July 2, 2004. Witnesses for these intervenors claim that the mitigation projects proposed by OG&E to resolve market power issues were not defined, and they attempt to claim that additional mitigation measures must be taken to address OG&E s market power which the FERC found to exist in its December 18, 2003, Order. I advise the Commission that the mitigation projects OG&E proposed in the FERC Proceeding, referred to as the 600 MW Bridge , was specifically defined by OG&E in the studies submitted, were evaluated by the FERC Staff and described in FERC Staff Affidavits submitted to the FERC Commissioners for consideration, and were determined by the FERC Staff to be sufficient to mitigate the market power the FERC found to exist in its December 18, 2003, Order. I advise the Commission that OG&E constructed the projects comprising the 600 MW Bridge, and on May 31, 2005, OG&E notified the FERC that those projects had been completed. I also advise the Commission that the FERC expressly recognized in its July 2, 2004, Order that the 600 MW Bridge was for the benefit of all wholesale market participants, and there was no guarantee that Redbud would have the use of 600 MW of additional ATC. These intervenors now claim that the 600 MW of ATC was not available to be used by Redbud during the summer 2005. I explain to the Commission that the denial of Redbud s request for firm transmission service in June 2005 could mean any of several things, including the commitment of ATC to other market participants, changes in power flows, or changes in generation dispatch. With respect to the claim that additional upgrades to the transmission network are necessary, I advise the Commission that when OG&E closed on the McClain purchase on July 8, 2004, neither I nor anyone else to my knowledge at OG&E had any reason to believe that projects other than those approved by the FERC would be required to provide the 600 MW Bridge.

**Steve Goodner**

In my direct testimony I describe the development of the Company s cost-of-service study. The cost-of-service study is used to determine OG&E s total revenue requirement and then to allocate the cost of service components to determine the revenue requirements for the Oklahoma customer classes and subsequently to develop rates of return for each such customer class. I sponsor schedules in Section K, Section L and various pro forma adjustments in Section H, Schedule H-2 of the Company s Application Package. Section K sets forth the Company s Cost of Service and jurisdictional calculations and Section L presents the Oklahoma jurisdiction class amounts to be used as a basis for rate design. The pro forma adjustments I support are made primarily to normalize the test year and to properly match fuel expense with the associated revenue. I support changes to the Rider for Fuel Cost Adjustment to achieve two goals: first, to allocate fuel related costs in a manner that better follows cost of service procedures; and second, to charge each customer a cost per kilowatt-hour that is more representative of the actual cost to provide the energy at each service level. I request the Commission accept the cost of service study submitted in this case for the setting of new rates for the Company.

18

---

My rebuttal testimony addresses comments and issues included in the testimony of Mr. Glen Gregory for the Oklahoma Industrial Energy Consumers. I disagree with Mr. Gregory s allegation that OG&E has misallocated fuel costs to customers. Mr. Gregory fails to recognize that no customer or class of customers has an exclusive right to specific plants or energy prices and that the Company meets system customer demands in all jurisdictions on a joint basis. The Company s allocation of fuel costs follow the traditional average cost causation principles prescribed in the NARUC s Cost Allocation Manual and approved by this Commission in prior rate cases. I disagree with Mr. Gregory s suggestion that the large industrial customers should receive differential pricing because of their high load factor and different energy usage patterns. Mr. Gregory s suggestion is based on the faulty assumption that during the OG&E peak demand months of June through September of the test year LPL customers cause higher capacity factors on the coal plants which in turn causes fuel savings to all customers. The LPL class is not the sole or even major user of KWHs in the off peak periods for these months but is in fact, one in a group of joint users. Mr. Gregory s review of the LPL class demand and energy usage changes made an apples to oranges comparison of the difference in the LPL class demands and energy usage between the Company s current filing and last adjudicated case (PUD 200100455). Mr. Gregory did not accurately calculate the Company s LPL class Maximum Demand because the LPL class On Peak Demand and Maximum Demand Billing Units used by Mr. Gregory did not include all the required demands associated with the Conoco special contract, the Oklahoma State University special contract, the LPL TOU IR-1 billing units, and the Real Time Pricing customers. Mr. Gregory should not have used the Average and Excess Demand allocator as the basis for assigning specific plants and the associated energy cost of those plants to customer classes. All production plant meets the demand of all customers jointly and Mr. Gregory also incorrectly assumes that the AED allocator assigns fixed production costs by specific plant. In addition, the time of use fuel adjustment clause (TOU FAC) proposed by Mr. Gregory should not be used as the vehicle to provide differential pricing to the large industrial class. In his cost of service, Mr. Gregory failed to equally reflect in class revenues his fuel and purchased power expense adjustment, thus overstating the class revenue for the test year.

I have shown that each customer class should bear a responsibility based on the average costs that the Company has to incur to provide the joint requests of all its customers. I believe that average costs paid by customers are fair just and reasonable and follow sound cost causation principles. I have also shown that on a physical basis all customers are jointly placing demands on the system at the same time during on peak and off peak hours. Because of this joint usage pattern, no class has a greater right to differential pricing than any other class. Joint usage merits joint average pricing as proposed by Mr. Walkingstick.

**Steven K. Holloway**

My testimony supports rate base pro forma adjustment Nos. 4 and 5 and Operating Income Statement Adjustment No. 24. Adjustment No. 4 to Rate Base recognizes coal and fuel oil adjustments to inventory totaling $15,199,401. The inventory adjustment is based on a 75-day coal inventory and an increase in fuel oil inventory, which besides No. 2 oil includes an increase to a 21-day supply of No. 6 fuel oil at Seminole. As I discussed, these inventory levels are essential to provide an appropriate balance between the risk of running out of coal and hedging against gas price extremes. Adjustment No. 5 to Rate Base recognizes a reduction in



---

OG&E s gas inventory at test year end in the amount of $3,032,041 to reflect a 7.5 Bcf inventory level. My testimony also supports Operating Income Statement Adjustment No. 24 to recognize the annualized O&M expenses associated with the McClain Plant at $3,103,534. This adjustment annualizes the actual O&M costs for the McClain Plant for the last half of the test year and reflects the reduced costs related to the LTSA on a three-year average forward basis compared to the actual LTSA costs experienced during the test year. I ask that the Commission accept these pro forma adjustments for the purpose of setting OG&E s prospective rates and charges to its Oklahoma customers.

In my Rebuttal Testimony, I advise the Commission, based on *force majeure* events occurring on an industry-wide basis since the end of the test year, that OG&E accepts Staff s proposed adjustment recognizing a 60-day coal burn inventory level and reducing the Company s pro forma Fuel Inventory Level related to coal by $7,417,846. I explain why the OIEC s proposed adjustment to coal inventory should be rejected, because the OIEC recommendation would set the Company s coal inventory level based on *force majeure* events related to rail carrier derailments in May of this year. Staff advises the Commission that fuel oil is a good hedge against high prices in the natural gas market, and suggests a 16-day burn level for this hedge. In its proposed adjustment Staff failed to take into consideration OG&E s Number 2 fuel oil inventory; I advise that Staff s fuel oil inventory adjustment should be increased by $1,957,808 to allow for the 16-day fuel oil hedging inventory at Seminole. The fuel oil inventory recommendations of the OIEC and the AG should be rejected, because those parties fail to recognize the advantage of a fuel oil hedge to customers. Staff also makes an adjustment to O&M expense for McClain but failed to recognize the actual amount for non-fuel O&M for July. When the actual amount is recognized, Staff s adjustment is reduced by $31,426, resulting in a corrected adjustment increasing McClain O&M by $292,725 for a new total of $3,396,259.

**John A. Jeter**

My direct and rebuttal testimony is in support of the Company s proposed working capital amount to be included in rate base based on the lead-lag study prepared by the Company, which I reviewed. I described the revenue requirements lead-lag study methodology used by the Company, which includes all elements of cost of service. I believe that lead-lag study methodology is the most theoretically sound basis available. Some of the elements of cost of service included by the Company that are not included in the other witnesses versions of lead-lag studies are depreciation and amortization expense, deferred income taxes, amortization of the investment tax credit, and equity return. Collectively I will refer to these items and interest expense as capital items.

I explain in my testimony that such items must be included in this study in order to compensate investors for the entire investment required to provide service to customers. In the case of the items other than interest and equity return, I explain that the rate base is reduced for depreciation and deferred income taxes and increased for the amortization of the investment tax credit before the customers have paid, or had payments reduced, for them because of the lag in payments of revenues. Exhibit JAJ-1 is an illustration of the need to include depreciation in the lead-lag study in order to allow the Company to actually obtain the return allowed by the Commission. This example is also illustrative of the effects of deferred income taxes and the investment tax credit.

20

---

I also explain that equity return should be included in order to reflect the fact that it is earned when service is rendered, but not received until 39.47 days (the revenue lag) later. Interest expense (which is significant because it has a relative large number of lead days) is an offset to the other items.

My rebuttal testimony includes comments on the testimony of Staff witness Thompson, Attorney General witness Norwood, and OIEC witness Garrett. Each of these witnesses opposes the inclusion of the capital items other than interest expense discussed above. In addition, the Staff proposes to apply an interest rate, rather than the overall rate of return, to the working capital portion of rate base. I disagreed with that proposal because working capital is consistently a required investment and the required investment is not limited to debt funds.

Furthermore, Mr. Norwood proposes to exclude the average balance of unrecovered fuel costs from rate base. I believe that such costs should be included in rate base because that is the only way the Company investors can earn on the substantial amounts invested in this cost.

In discussing their opposition to the inclusion of the capital items in the lead-lag study, each of these witnesses refer to the term cash working capital and argue that the capital items (other than interest, which they would include in the lead-lag study) should be excluded because they are non-cash items. I point out in my testimony that the items are not non-cash . If the items are non-cash it is difficult to explain why they are included in cost of service and the related revenues each month are collected in cash from customers. The point of the inclusion of these items in working capital is that they are collected 39.47 days after service is rendered. I illustrate the effect on rate base of including depreciation in the study with my Exhibit JAJ-2.

**Dr. Laurence D. Kirsch**

The marginal cost of a product or service is the change in costs that accompanies a change in the use of that product or service. Marginal costs are one of the major bases for efficient prices in both competitive and regulated industries. In competitive industries, competitive processes automatically move prices close to the industries marginal costs. In regulated industries, prices based upon marginal costs create benefits for consumers by providing consumers with information about the cost of marginal production. In the electric power industry, such signals can induce customers to shift demand away from periods when electricity is expensive to produce and toward periods when electricity is relatively cheap to produce, thus making better use of the capital and fuel that are required to provide electric power service.

The marginal cost of real power is the sum of marginal operating cost and marginal outage cost. I forecast that, in 2007, OG&E s hourly marginal operating costs at generator locations will range from a low of $8.95 per MWh to a high of $64.67 per MWh, with coal-fired generation on the margin in 13.2% of the hours of that year and gas-fired generation at the margin in the remaining hours. I also forecast that marginal outage costs at generator locations will range as high as $129.89 per MWh, though 91% of the hours will have marginal outage costs of less than a dollar per MWh, and 97% will have marginal outage costs less than $10 per MWh. Virtually all of the marginal outage costs will fall in the summer months. Because of

21

---

transmission and distribution losses, marginal costs at customer locations will be 4.8% to 15.7% higher than at generation locations, depending upon the customer s service level.

To assess whether OG&E s rate proposal moves its rates toward more efficient levels, I compared the effective energy charges implied by the proposed rates, the effective energy charges implied by its present rates (adjusted for revenue requirements) and efficient Ramsey prices based upon marginal costs. OG&E s proposal clearly moves residential, GS, and PL rates in the direction of greater efficiency. OG&E s proposal for the LPL class, by contrast, is a mixture of more efficient and less efficient prices; but the net result is nonetheless greater efficiency than characterizes existing rates.

In response to the testimonies of Edwin C. Farrar (on behalf of the Corporation Commission of the State of Oklahoma) and Jess Galura (on behalf of Wal-Mart Stores East, LP), my rebuttal testimony makes three main points. First, efficient prices will reflect *marginal* fuel costs, not *average* fuel costs. Second, marginal costs change dynamically over time, even if physical generation plant does not change. Third, gas-fired generators are estimated to be on the margin in 87% of all hours. Consequently, the Commission should reject or discount testimonies of these witnesses to the extent that they rest upon assumptions or beliefs that conflict with these three points.

**Donald A. Murry, Ph.D.**

My direct testimony provides recommendations to the Commission for OG&E s capital structure, the cost of debt and the allowed return on common stock equity in this proceeding. My rebuttal testimony addresses issues in the testimonies of Misters Solomon, Thornton, Dunn and Farrar.

In preparing my direct testimony I reviewed the current economic environment, concentrating especially on recent and anticipated trends in interest rates, risk characteristics of the Company, the appropriate capital structure and costs of debt and common stock equity. Finally, I tested my recommendations to assure that they conformed to basic financial integrity tests.

As to the economic environment affecting the cost of capital during the time that rates from this proceeding will be in effect, the rising interest rates since 2003 and into the future are significant. The relevant capital structure, which supports OG&E s assets providing services in Oklahoma, is 44.31 percent long-term debt and 55.69 percent common stock equity. I confirmed that this capital structure conforms to current industry practice. The embedded cost of long-term debt is 6.03 percent.

To estimate the cost of common equity I applied two common market-based measures, the DCF and the CAPM methods, to both OGE Energy and a group of comparable electric utilities. The range of current DCF results based on expected earnings demonstrates its sensitivity to investor expectations and market prices. They ranged from 7.56 percent to 13.54 percent. Two less sensitive CAPM estimates were 11.46 percent and 10.74 percent for OG&E. For comparable electric utilities these results were 11.77 percent and 12.18 percent. Based on



these calculations, relative risk and economic factors, I am recommending an allowed return on common stock of 11.75 percent for OG&E or a return on total capital of 9.215 percent.

In my rebuttal testimony, I pointed out that I generally concur with Mr. Dunn and Mr. Farrar regarding the proposed capital structure. Both Mr. Solomon and Mr. Thornton, however, propose using the corporate capital structure. However, neither of them justify using a capital structure that is different from the one supporting the assets serving Oklahoma electric customers. As to recommended costs of common stock, Mr. Solomon relies exclusively on a DCF method that employs a discredited growth rate calculation. Mr. Thornton used the same discredited calculation in his DCF. Also Mr. Thornton selected market-high data to measure the market risk premium for his CAPM that results in a biased, low estimate. Mr. Thornton and Mr. Farrar both failed to acknowledge that the CAPM analysis has a well-recognized bias when used to estimate the cost of capital of smaller companies. If they had followed the instructions of their data source, in both cases their CAPM results would have been close to my estimates.

**John J. Reed**

In my Direct Testimony, I testify to the prudence of OG&E's acquisition of the McClain generating facility pursuant to the requirements of the October 11, 2002 Joint Stipulation and Settlement Agreement. I describe the market environment and other relevant circumstances faced by OG&E during the contracting period (September 2002 - August 2003) and apply a common utility industry prudence standard to the process undertaken by OG&E to acquire McClain. I also examine the value paid by OG&E for McClain based on comparable transactions during this same time period.

My principal conclusions are:

The McClain transaction met the requirements established by the Stipulation on very favorable terms, leveraging a regional market oversupply situation that existed during the contracting period.

The market environment and circumstances faced by OG&E during the contracting period strongly favored the asset purchase option, relative to the alternative build or power purchase options.

The process employed by OG&E that combined screening and multi-party negotiations was prudent and resulted in a favorable outcome; an RFP-based process was not well suited to the circumstances faced by OG&E.

The McClain transaction was a good deal for customers when it was executed, and should remain a valuable asset in OG&E s portfolio throughout its useful life.

The common utility prudence standard that I propose be adopted by the Commission was established in 1923 in a United States Supreme Court decision. That decision, and its application since, has established two fundamental principles of ratemaking. The first principle is that only reasonable or prudent expenditures are to be included in a utility s rates. The second principle is that a utility s expenditures are presumed to be prudent until it can be demonstrated that the expenditures were imprudent through clear evidence of utility misconduct.

In my Rebuttal Testimony, I respond to testimony sponsored by Mr. Daniel Peaco on behalf of the Oklahoma Industrial Energy Consumers ( OIEC ), Mr. Scott Norwood on behalf of the Office of the Attorney General ( AG ), Mr. Judah Rose on behalf of Redbud Energy, LP ( Redbud ), and Dr. Marcus Durham on behalf of AES Shady Point, Inc. ( AES ).

These witnesses assert that OG&E should have relied upon short-term and intermediate-term purchased power arrangements to deliver the $75 million customer savings called for in the Joint Stipulation and Settlement Agreement. They apply hindsight in recommending prudence disallowances based on this strategy. However, as described at some length in my Direct Testimony, there were many risks and flaws associated with this strategy, risks that were particularly high during the time period under review. These risks included bankruptcy (termination of the contract), imputed debt costs and weakening of OG&E s balance sheet (with resulting higher short-term and longer-term financing costs), and having to contract for replacement capacity at a time when the market was much anticipated by experts to be tighter.

In contrast, the course of action implemented by OG&E was a prudent and appropriate response to satisfy its public service obligations. OG&E acquired a long-term asset, located in its service territory, at a discounted price. In doing so, it avoided the very substantial merchant plant counterparty risk that existed during this time period. OG&E avoided the construction and market value risk of building a new plant in an already overbuilt market. Finally, OG&E avoided the risk of having to contract for capacity at a later date when the market was largely anticipated to have worked through its capacity excess.

**John J. Spanos**

My direct testimony sets forth the results of the depreciation study prepared for Oklahoma Gas and Electric Company as applied to electric plant in service as of December 31, 2004. The concepts, methods and basic judgments which underlie recommended annual depreciation accrual rates related to current electric plant in service are described.

The results of the study, including summary tables, survivor curve charts and life tables resulting from the retirement rate method of analysis; tables of simulated and book balances resulting from the simulated plant record method of analysis; tabular results of the historical net salvage analyses; and detailed tabulations of the calculated remaining lives and annual accruals are discussed. An explanation of the life span technique is described for generating facilities.

For most accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. For certain General Plant accounts, the annual depreciation was based on amortization accounting. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group.

My rebuttal testimony focuses on the appropriate life span for the McClain facilities.

24

---

**Roger D. Walkingstick, P.E.**

In my Direct Testimony I support the rate design proposed by OG&E in this proceeding. I address certain pro forma adjustments to the test year for weather normalization, fuel matching, year-end customer changes, and other adjustments historically approved by the Commission, and I address OG&E s long-term rate design goals, particularly as they relate to subsidies and marginal cost rate design and structure. I discuss rate design trade-offs, the proposed rate design for major classes to mitigate unreasonable subsidies, and describe proposed changes to the Company s Terms and Conditions of Service. I describe the impact of OG&E s proposed rate design on customers competitive positions within our region and nationally. OG&E s revenue deficiency as established in its Application Package, is approximately $89.1 million. Much of that deficiency is attributable to two major classes, Residential and Large Power and Light ( LPL ). The two remaining classes, General Service ( GS ) and Power and Light ( PL ) provide substantial subsidies to the Residential and LPL classes. While I am proposing that the subsidy to the LPL class be eliminated, I believe the rate impact of completely eliminating the subsidy to the Residential class would be too severe. I sponsor pro forma revenue adjustments numbered 2 through 8 in the Company s filing, and I describe each of those adjustments in my testimony. From a long-term perspective, I identify three issues that need to be addressed: existing subsidies among customer classes should be minimized, new rates should reflect a rate design consistent with marginal costs, and additional customer rate options should be offered to our customers. The rate design I propose reduces but does not eliminate the subsidy to the Residential class and eliminates the subsidy in favor of the LPL class. Marginal costs have always been an important consideration; with escalating fuel costs the importance of marginal cost analysis has become extremely important. Marginal cost pricing encourages consumers to use electricity wisely by sending the correct price signal. OG&E s current rate structure sends the opposite pricing signal to its customers. In my discussion of rate design trade-offs, I discuss the guidelines that have been used by regulated utilities for decades. Rate design can rarely satisfy all of the rate design guidelines, but every effort should be made to satisfy as many of the guidelines as possible. In this case it is impossible to eliminate subsidies and simultaneously reflect gradualism given the class rates of return and the sizes of the class revenue deficiencies. Two issues required special funding attention in OG&E s overall rate design proposal: the Military Base Rider (MBR) and the newly created classes for schools. The MBR required approximately $2.7 million while the school classes required approximately $1.9 million. My testimony describes the justification for the MBR and school classes. My testimony also describes in detail the changes I propose to the rate design for the major classes of service, includes my recommendation to make the GFB pilot program a permanent tariff, my approach to seasonal energy pricing, the need for a power factor correction for SL 1 and SL 2 customers, proposed changes to the Cogeneration Credit Rider and the Green Power Wind Rider, and to the special classes of customers such as OGP, MP, LM, and OSL. I also sponsor the Company s proposed Major Storm Rider and the Custom Contract Tariff. Changes proposed to OG&E s T&C tariffs relate to the elimination of Field Bill Collections for safety reasons and updates to the T&C fee structures for Service Initiation, Service Reconnect, Alternate Payment and Late Payment Charge, all of which are identified in Table 2 in my Direct Testimony. I conclude my Direct Testimony by advising the Commission that if the rates for the classes are approved by the Commission as proposed, OG&E s customers should continue to compare favorably on both national and regional bases.

25

In my Rebuttal Testimony I address claims and assertions made by OIEC witness, Glenn Gregory, Wal-Mart witness Jess Galura, and Staff witness Ed Farrar. Mr. Gregory opposes the changes to the LPL class rate design because many of the OIEC members are large energy users who benefit from the current structure at the expense of the rest of the class. The change I have proposed is simple and straight-forward: by reducing or removing the tailblock pricing differential, very large customers no longer will receive the price break and resulting subsidy they currently receive. Mr. Galura proposes no rate increase for the six classes of service that are above the average ROR for the jurisdiction, but he fails to address the remaining three classes that are below the jurisdictional average ROR, and he fails to address funding requirements for the Residential and the two new school classes of service. Since his recommendations do not resolve all of the funding requirements for all classes of service, Mr. Galura s recommendations should be disregarded. Mr. Farrar discusses the advisability of providing customers with incentives to modify their usage patterns, suggests that customers that take appropriate action to manage their load should be rewarded, and discusses the concept of an umbrella-style approach of developing programs that could be added or modified as programs are developed to provide proper customer load management incentives. I advise the Commission that conceptually I agree with Mr. Farrar s ideas, and I believe in time these programs could be developed and implemented. However, his umbrella approach is extensive and far-reaching, will require research and development efforts and will take months to create. Mr. Farrar also suggests that recovery of transmission related expenses be moved from base rates to the FAC. I compliment Mr. Farrar for his recognition that the SPP marketplace is evolving, but I suggest the Commission has a number of ways by which these costs and revenues can be addressed. I doubt that a single recovery mechanism would be adequate to handle the total complex workings of this new marketplace.

**Gene H. Wickes**

The purpose of my direct testimony is to explain the basis for and development of the pension, retiree medical, and retiree life costs used by OG&E in this proceeding and provide my expertise in support of that basis. OG&E accounts for the cost of their pension plan under the rules set forth in Statement of Financial Accounting Standards No. 87 (FAS 87). FAS 87 sets forth the rules that companies must follow in determining their pension costs in order to follow Generally Accepted Accounting Principles (GAAP). In my testimony, I outline the basis for pension accounting, and provide extensive detail on the components and factors that impact pension accounting. In addition, I provide the basis and components for retiree medical and life accounting.

George Mathai of the Oklahoma Corporation Commission (OCC) and Mark Garrett of the Oklahoma Industrial Energy Consumers (OIEC) have provided testimony recommending adjustments to the pension and postretirement medical costs presented in my direct testimony. Their recommendations do not comply with FAS 87 or GAAP. They suggest changes to the expected return on asset assumption, changing the methodology for calculating and amortizing unrecognized gain loss, and changing the calculation of service cost and expected return on assets.

Their proposed change to the expected return on asset assumption would be inappropriate based on the target asset allocation, and expected returns by asset class. Also, I do not agree with the staff s calculation of net unrecognized gain loss, as it does not comply with FAS 87 or GAAP. Nor do I agree with the staff s method for amortizing the unrecognized loss. OG&E currently amortizes the minimum permissible amount under FAS 87 in determining net periodic pension cost; their recommended amortization amount is less than this FAS 87 permitted minimum. The calculations used by the staff for interest cost and expected return on assets do not take into account the trust s cash flows during the year. Adoption of the adjustments proposed by Mathai and Garrett could result in increased volatility in pension expense. If OG&E implemented the staff s recommendations, OG&E would not be determining pension cost in accordance with FAS 87 or GAAP. Furthermore, since regulatory accounting follows GAAP, the staff s recommended adjustments would also not be following regulatory accounting.

In summary, I recommend that the Commission reaffirm the applications of GAAP to pension and postretirement medical cost, and accept the calculations that are presented in my direct testimony.

**OG&E SHAREHOLDERS**

**John C. Dunn**

My name is John C. Dunn. I am a consulting economist on financial and regulatory matters. My qualifications as an expert have been accepted by this Commission. I prefiled responsive testimony on September 12, 2005, and rebuttal testimony on September 29, 2005, for the OG&E Shareholders Association on the following issues:

Capital Structure

Oklahoma Gas and Electric Company ( OG&E or Company ) is a fully integrated electric utility. OG&E has its own capital structure and its own cost of debt. The capital structure attest year end, 12/31/04, was 44.33% long term debt and 55,687% equity. Schedule 2 contains an analysis of the revenue, the number of customers and the debt and equity ratios at December 31, 2004 of the proxy companies that I have selected from the *Value Line Investment Survey Central Edition,* July 1, 2005. The average equity ratio of the group is 46.27%. That equity ratio is lowered by two companies with extraordinarily low equity ratios (CenterPoint Energy, Inc. with a 13.3% equity ratio and TXU Corp. with a 4.9% equity ratio). Both of these low equity ratios are holdovers from ill-advised diversification efforts. When those two companies are properly removed, the average is approximately 51% and is reasonably representative of the industry equity ratio and is consistent with the equity ratio of OG&E on 12/31/04.

Schedule 3 is an analysis of the equity ratios for each of the eighteen proxy companies for each of the years 1995 through 2004, taken from the *Value Line Investment Service* July 1, 2005. It indicates a gradually increasing equity ratio that is based at approximately 50% in the 1995 to 1999 period. Beginning in the year 2000, the equity ratio declines to about 45%. A portion of this decline is caused by erosion in TXU and MGE. By the year 2004, TXU has an equity ratio of 4.9% as previously indicated, and CenterPoint has an equity ratio of 13.3%. Again, if those companies are eliminated, the equity ratio for the group is increased to above 50%. OG&E s

27

---

equity ratio is somewhat higher than the equity ratio of my proxies, but it is in the range of reasonableness.

The higher equity ratio has benefited the Company in the past by contributing to financial flexibility and a lower cost of debt. A higher equity ratio helps to assure the financial wherewithal and flexibility to meet its obligations in difficult times.

I rejected using the OGE Energy Corp. consolidated capital structure because it was inappropriate for revenue requirement purposes. A consolidated capital structure is only the summation of all of the individual division and subsidiary capital structures of a company, plus or minus accounting eliminations. The consolidated capital structure has no particular or necessary relationship to the appropriate capital structure for any one of the individual entities which make up the total. Furthermore, the book capital structure of OG&E is a result of deliberate management decision and action. The actual capital structure is presumed to be prudent, and should be used for ratemaking purposes, unless under *Turpen v. Oklahoma Corporation Commission,* 769 P.2d 1309 (OkIa. 1988), one proves that capital structure is more equity laden than needed for regulated operations, i.e., proves, I believe, that the book capital structure is extremely different from the industry, not just slightly different but still within the reasonable range. None of the witnesses who proposed a hypothetical capital structure did any study of the risks inherent in providing service and did not testify that 55.687% equity was more equity laden than needed.

Mr. Hatfield described in some detail the 2002 Settlement Agreement that must also be considered in this proceeding, because it is considered by the investing public and market analysts in establishing their expectations. In 2002, the Company agreed to a plan of action which involved first the Company absorbing a $25 Million rate reduction and committing to a phased- in customer savings plan of at least another $75 Million over 36 months. Moreover, the Company agreed to a specific performance metric to measure the promised phased-in customer savings, basically the sum of avoided purchased capacity, cogeneration credits and fuel savings (made possible by acquiring a new generation facility), less the cost of that new generation facility. The Company agreed to those terms on the expectation that it could successfully perform and that, when it did, this regulatory authority would allow an adequate return, commensurate with the risk, on that investment in this rate case. The Company is performing on the plan in anticipation of this rate increase. It absorbed the rate decrease, purchased a power plant, experienced some delays and then filed for a rate increase which reflects the acquisition of that power plant among other things. This pattern of events created, in my opinion, additional risk for OG&E. That risk affected bond ratings, as demonstrated by the downgrading of Company debt, and affects expectations of analysts and investors. Following the settlement in 2002, Moody s, as reported by Mr. Hatfield in his direct testimony, indicated in an opinion updated on April 11, 2003, that its confirmation of A2 ratings is based on the assumption that the Company would maintain the capitalization stipulated by the Oklahoma Corporation Commission. The settlement was based on a common equity ratio of 56% and I believe that any equity ratio significantly below that level would result in further downgradings of the Company s debt securities.

28

The Legal Standard For Rate Of Return

I followed the *Bluefield* and *Hope* standards, adopted in *Turpen* recognizing the importance of comparable earnings, financial integrity, capital attraction and the changing level of returns sensitive to investment opportunity, the market, arid business conditions.

Current Capital Market and Utility Industry Conditions

The economy is in a robust state of growth. The current level of inflation is reasonably low, not exceeding 3% and, in many quarters, not expected to exceed 3% assuming the Federal Reserve is successful in its endeavors to cool the economy to forestall or eliminate inflationary pressures. The Federal Reserve s process for cooling the economy has been to raise interest rates, ratcheting up short-term capital costs at the rate of a quarter of a percent per Federal Open Market Committee meeting each of the last eleven meetings, including on September 20, 2005, after hurricane Katrina. The Federal Reserve has promised further measured increases in interest rates. We are experiencing extraordinarily high crude oil prices that translate into high prices for crude products such as gasoline and has a spill over effect onto the cost of natural gas. There is a reasonable expectation that these high energy prices will eventually become a catalyst for broader and higher inflation. If the Federal Reserve is not successful and if the increases in energy prices work their way into final goods and services, there will be a significant amount of inflation in the price structure of our economy. That will lead to a significant increase in the cost of capital.

The electric utility industry has recently experienced three significant negative events: 1) market disequilibrium that materialized in the western power markets, leading to the bankruptcy of a major electric utility, extreme escalation in the cost of wholesale power, and significant disruption for many participants in the industry, including lenders and shareholders; 2) an outage on the east coast that led to significant disruption and discomfort and, I believe, a questioning of the quality and reliability of the electric utility system and the competence of those operating (and regulating) the electric utility industry; and 3) failed diversification efforts by many electric utilities. These factors tend to increase the cost of capital by making investors acutely aware of the fact that there is much more risk in electric utility investing than was traditionally believed. OGE Energy Corp. and OG&E have not been involved, directly or indirectly, in any of these utility-wide problems. Unfortunately, the impact of these problems spills over and causes potential investors to attribute higher levels of risk to any utility investment. Investors are wary and cautious to select only those electric utilities that have proven records of quality management, which are reasonably regulated and which have reasonable financial parameters.

OG&E has provided service in a quiet and efficient manner, with an admirable and improving reliability record. OG&E is highly regarded by its customers and its peers. In a recent survey by JD Power and Associates, OG&E rated second highest in overall customer satisfaction in the southern United States. It rated highest in customer communication. (The Oklahoman August 6, 2005). The Company has a quality management. It has been devoted to its primary objective, which is providing low-cost and reliable electric service, and it has been regulated in an even-handed fashion to this point in time. It has relatively low rates and, while its financial profile is not among the best, it is reasonable. An adverse change, for example, a change in the management attitude or capability or in the regulatory environment, or some

29

combination of these factors, can move a company from a potentially attractive investment to an undesirable investment. If that occurs, among other things, its cost of capital goes up, its access to capital goes down, and its ability to provide service to its customers at reasonable costs is diminished.

Investors and Risk

Every dollar of investment capital used to support OG&E s rate base is ultimately supplied by individuals for whom return is important, maybe critical. Approximately 20,000 of those individuals live in Oklahoma and own approximately 16,000,000 shares. Some of those individuals depend upon OG&E for at least a part of their current income, their retirement planning, and their retirement income. The customers of OG&E do not supply the capital, except as also investors, and do not own the assets. Only shareholders bear the risk of ownership.

Investors choose individual investments from the wide variety of investment alternatives available. Investors rank these risk-return pairs with the best combination of risk and return available at the top of the list or the most desirable investment. The best investment combines the lowest risk and highest return available within the risk class.

At any time, there are usually a number of investments, which are similar, but there are always slight differences in both risk and return -- either real or perceived by investors. It is within this group of near alternatives that the opportunity cost for a similar investment will be found. To be an attractive investment alternative and to have access to the capital needed to meet customer demands, it is necessary for OG&E to have risk-return characteristics which cause its securities to rank among the investment grade choices within the appropriate risk category. Since little can be done to lower or change the risk of OG&E, the return must be set to match the risk of OG&E. That risk is electric utility proxy group risk plus or minus the risk effects of the specific OG&E operations.

The Proxy Group

I identified a group of companies that have most of their activities confined to the electric utility business, as reported in the July 1, 2005 *Value Line Investment Survey*. I eliminated five companies: ALLETE, Aquila, CMS Energy Corp., DPL, Inc., and Westar Energy, Inc. ALLETE was eliminated because it recently undertook a major corporate spinoff. The other four companies were eliminated from the group because they are below investment grade.

The proxy companies constitute a reasonably homogenous group of Midwestern electric utility companies. The companies reflect the characteristics of reasonably sized, publicly traded, well known companies that can be used as the basis or starting point of an analysis to determine the required return on common equity for a similar nontraded electric utility company. Although some of the companies are diversified, they are still recognized as primarily electric utilities and a reasonable investor could select this group as the group of alternatives if making an investment in an electric utility such as OG&E.



---

Cost of Common Equity

I used the Discounted Cash Flow ( DCF ) model to calculate a baseline, industry cost of equity for that proxy group. This became an unadjusted electric utility ROE requirement that is suitable only for a company precisely identical to the average of the proxy group. The baseline is therefore a starting point and not the conclusion. The baseline must be adjusted for the risk associated with the subject company (OG&E) and its unique characteristics. I then compared the level of OG&E risk to the risk of the pure play or proxy group to establish the relative risk vis-a-vis the proxy group. Based upon this analysis and my assessment of the near term future, I estimated the risk-adjusted cost of equity for OG&E.

Impact of New Industry Dividend Policy on the DCF Analysis

Dividends are used in the DCF formula to measure a part of the return received by investors. Now and in the future, tax efficient growth in earnings will be the primary driver of investor return rather than growth in dividends as in the past. Historic dividend data cannot be used uncritically. I supplemented the historic data with an analysis of earnings forecasts. A proper analysis also requires consideration of flotation and pre-offering pressure. The analysis involves the calculation of each of the components of the DCF model. This requires first developing a reasonable estimate of investor growth expectations, the available dividend yield and the cost of flotation and pre-offering pressure. The elements are then combined. Once the DCF cost of equity is determined for the proxy group it will be adjusted to the specifics of OG&E.

Determination of Growth Rate

Expectations are the real basis for any investor s decision. I determined the growth rate like an investor would based on analysis of historic data, current market reports and forecasts prepared by professional analysts. Dividend growth is no longer the primary driver in shareholder return. It is new earnings growth and related book value growth (the earnings base), as dividends are retained. Schedule 4 is an analysis of the five- and ten-year growth in earnings, dividends and book value calculated and reported by Value Line dated July 1, 2005, for the proxy group. The data for the five year term is distinctly different from the ten year data. The relative rate of dividend growth has obviously slowed from the ten year period to the five year period while the growth rate for earnings and book value have increased. Consistent with the new dividend policy discussed above, the five year dividend growth rates are lower than the ten year rates. This is an important point. For the ten year period, the growth rates are moving more or less in tandem, as would be expected under the older model of the industry with parallel growth in earnings and book value although dividend growth lags. The more recent growth rates in earnings and book value are also significantly higher than the longer term ten year growth rates. This is also to be expected because the relative retention rate is higher as a consequence of the slowing in dividend growth. If the dividend rate continues to slow, the impact of the slow down will be reflected in still higher earnings growth, and the future growth rate should be higher than the current five year historic rate.

In selecting a group of companies to set a standard, investors would prune the bottom of the group and select an investment from the best. There is no requirement that the investor buy



---

the average and certainly no requirement that an investor buy an average depressed by a few bad observations or poorly operating companies. I believe a typical investor would tend to gravitate toward the higher growth rates which help make up the averages, expecting that individual growth rates higher than the average would be better than just average rates.

I also examined the forecast growth rates as forecast by the *Value Line Investment Survey* of July 1, 2005 for this proxy group. That data is shown on Schedule 4, page 2. That analysis showed that Value Line expected somewhat faster growth overall in the future than in the past. It also showed that Value Line expected earnings to grow almost two percentage points or almost 50% more rapidly than dividends.

OG&E must compete not only within the industry but also with individual companies in the industry for new equity. This means that it must compete not only against the average of the industry but also against the best. I say this because most investors prefer to avoid the poorly performing companies in favor of the better performing companies. As a consequence, OG&E will face competition with growth rates in the 5.50% to 8.50% range.

I examined the growth in earnings, dividends and book value per share for each of the companies for the period 1995 to 2004. Schedule 5 contains an analysis of the dividends paid per share by each of the companies for each of the years from 1995 to 2004, and the calculation of an average of the one-year growth rates for the period 1995 to 2004. Schedule 6 is a parallel analysis of growth in earnings for the comparative companies. Schedule 7 contains the same type of analysis of book value per share for the proxy per share for the proxy companies. The calculation used in Schedules 5, 6 and 7 is an additional method (in addition to the calculation used in Schedule 4 which is the *Value Line* method) to eliminate the effect of single year influences by averaging the results of each growth pair in the period to determine the period average.

I also examined the *Thompson Financial First Call* reported estimates of future growth for individual companies. For the entire electric utility industry, the analysts expect growth in the range of 11.2% for next year. For the next five years, the analysts found a growth rate of 5.25%. The growth expectations for the electric utility industry for many of its companies for the next year are very high. The growth rates for the five-year period are more moderate and somewhat lower. Many analysts tend to be very conservative on long range growth estimates simply because of the difficulties associated with making a longer term forecast and the risk to individual analysts of making such forecasts and subsequently being proven wrong. As a result, I gave little weight to the long-term forecast and, because of the erratic nature of the short-term forecast, I did not accord any weight to the extremely high one-year growth rates but will consider the fact that short-term expectations are high.

Based on the fact that the rates of growth are trending up and that the forecast growth in earnings by Value Line is 6%, I believe a reasonable investor growth expectation for an electric utility company such as OG&E is in the range of 6% to 6.75%. This is the same as the Value Line forecast with some influence by the one-year Thomson forecast.

32

---

Determination of Dividend Yield

The first step in my analysis of dividend yield is contained on Schedule 5. This schedule details the actual dividends paid by each of the proxy companies for the years 1992 through 2002. This information shows consistency of payment in each of the years for most of the companies. It also reveals steady growth in the dividends of the proxy group which is slowing over time.

The next step in the dividend yield analysis is a review of the current dividend yield. I have selected dividend yield data from the *Value Line Investment Survey* dated April 1, 2005 and July 1, 2005. I have also analyzed yields from the Wall Street Journal August 15, 2005. The data for that analysis is contained on Schedule 8. The yield is in the range of 4%. I concluded that the appropriate dividend yield to include in my pit-market adjustment DCF calculation was 4.00%. This yield approximates the average of the three data which are relatively stable.

The return on equity which is being established in a rate proceeding is first a return for the long term investor, not the day trader, and secondly, it is a return which looks forward for a reasonable period of time. Looking forward, an investor making a commitment today would assume that the components of return to be earned by that investment would include not only the current dividend paid in dollars but also any increase in that dividend paid in dollars during the first year of ownership. To ignore reasonably certain increases in dividend which are expected by investors evaluating securities is simply to understate the return on equity requirement. The pre-adjustment dividend yield resulting from my analysis is in the range of 4.0%. This calculates to an adjusted yield of 4.1% (4.0% x 1.02).

Flotation costs and price pressures result from the sale of equity. The effect should be reflected in the cost of common equity. Such an adjustment is frequently based on a study contained in *Public Utilities Fortnightly* by Borun and Malley which indicates the average flotation cost of the common stock issued is 5.5%. With this adjustment, the calculated dividend yield component of the cost of equity should be increased to a range of 4.3% (4.1% ÷ 94.5%).

Baseline Cost of Common Equity

The adjusted dividend yield is in the range of 4.3%. The minimum expected growth is 6.0% to 6.75%. Combining the dividend yield with the dividend growth rate indicates the DCF baseline estimate or the bare bones cost of common equity is 10.3 % to 11.05% for the proxy group. I believe that a return on equity in the range of 10.30% to 11.0% is appropriate to incorporate into a cost of service determination for an electric utility company which is equal in risk to the average of the group, based on my analysis which is historic for the growth variable and terminated at year end 2004. With the increases in capital cost imposed by the Federal Reserve since that time and their promise of more near term increases plus the heightened threat of inflation, I believe that 11.0% return on equity is the appropriate return for a group average company. The appropriate range of return for central electric utilities centers on the 11.0% return and should be increased above that amount for higher than average risk and lowered for less than average risk based on the characteristics of the specific company compared to the group.



---

Risk Adjustment/Statistical Risk Calculation

The cost of equity of the proxy group is based on the average risk of that group and must be adjusted to reflect the risk level of OG&E by using the standard deviation and the coefficient of variation, which I calculated. I converted the standard deviation to a coefficient of variation and calculated those statistics for OG&E, and for the industry average. OG&E s risk was greater than the level of risk in the industry Proxy Group. This calculation is on Schedule 9. In this case, the coefficient of variation indicates that the group average earnings vary by 1.38% but that the OG&E earnings vary by 15.93%. This is a very significant difference and strongly suggests that OG&E has a much higher level of risk than the average of the group. Under accepted financial theory, this means that OG&E requires a much higher return to be competitive in the market for capital.

Recommended Return on Equity

The proxy group current cost of common equity is in the range of 11.0% to 12.0%, centered at 11.0%. As a practical matter, the return component in the cost of service of a company with a risk profile equal to the average of the proxy group should not under any circumstances be lower than this amount, i.e. 11.0%. Given the somewhat greater risk of OG&E s operations as compared to the industry group, a return on equity of 12.0% is now reasonable and warranted as suited to that risk. If the Federal Reserve finds it necessary to increase capital cost more rapidly or to a higher level than now anticipated, it may be appropriate to increase the return on equity above the 12% level. A minimum return of 11.55%, as included in the 2002 Settlement Agreement is the absolute floor and that level should not be breached under any circumstances.

ROR Determination

Based on the OG&E book capital structure as of 12/31/04, its book cost of debt at 6.03% and a cost of equity in the range of 11.55% to 12%, I have determined that the minimum reasonable rate of return ( ROR ) for OG&E is in the range of 9.10% to 9.35% (Schedule 10). This ROR, and the ROE it incorporates, reflects the risks associated with the OG&E electric utility system.

Rebuttal Issues

Attorney General s witness, Mr. Norwood, proposes a 50 basis point ROE penalty for alleged imprudence in the acquisition of the McClain facility without any supporting evidence. He did not testify the acquisition was imprudent. He did not provide evidence to support any adjustment, much less one of the magnitude of 50 basis points. Claimed imprudence in acquisition of McClain is, in any event, a rate base issue. Any adjustment should be made there, not to ROE.

Witness Solomon s suggested 8.4% ROE is patently wrong. Both tax-exempt bond and preferred stock investments of less risk are yielding real or tax-adjusted returns greater than that 8.4% and equal to, or nearly so, the 9.0% proposed by Mr. Thornton.

34

---

All of the recommendations opposed to the Company are so low that the interest coverage will be inadequate and the Company s bonds will, in my opinion, be further derated.

PUD Staff witness Farrar, OIEC witness Thornton and Attorney General witness Solomon did not determine a return which is commensurate with the risk incurred by the current OG&E equity investors. They used so-called comparable groups of utility companies, but those companies were not at all comparable to OG&E, or to each other, and the return derived for the group is not appropriate for OG&E. Witness Thornton recommended 9.0% when the Value Line forecast ROE for his comparable group averaged 10.45% (Rebuttal Testimony of John C. Dunn, Exhibit C ).

None of the witnesses properly used a proxy group and then properly risk-adjusted the return derived for that proxy group to be reflective of the OG&E risk. The Thornton and Solomon analyses are incomplete and essentially useless without such a risk adjustment.

Staff s witness, Mr. Farrar, recognized the need to make an OG&E-specific risk adjustment, but the amount of the increase was too small and was added to a baseline not comparable to the electric utility.

All other analyses tend to be number driven and recommendations are made by averaging averages. I believe that is an inappropriate way to determine the cost of common equity. Too much is at stake in this proceeding, including the viability of the company and the equity with which its investors are treated. If those investors are not treated fairly now and provided the opportunity to earn reasonable returns, OG&E will not have the ability to attract the equity necessary to meet the requirements of its customers. Finally, no witness has provided any indication to the Commission with respect to an appropriate fair value rate of return on a fair value rate base. This further compounds and complicates the return on equity issue. OG&E s opponents not only urge hypothetical capital structures and deficient returns on equity, but also ignore the fair value of the rate base. This compounds the unfairness to OG&E and its shareholders and should not be followed by the Commission.

**AES SHADY POINT, LLC**

**Dr. Marcus O. Durham, P.E.**

In my direct testimony I have explained the process by which OG&E failed to make a prudent purchase of power. The McClain acquisition miserably failed in meeting the major components identified in the Stipulation Agreement.

OG&E s actual costs to purchase the McClain facility are much greater than the $160 million transaction cost identified by OG&E. The total investment for the McClain acquisition, including FERC-mandated mitigation, totals $226,855,396, for an annual cost of $112.41/KW and a total investment of $567/KW. Alternatives that were considerably cheaper and that did not hold similar risks were dismissed by OG&E. OG&E committed to a track early on and failed to update their decision as conditions changed. McClain cost recovery should be disallowed because the acquisition was imprudent.

OG&E chose not to rebut my testimony which contains the following salient points in relationship to the imprudent purchase of McClain by OG&E.

- OG&E improperly used the stipulation agreement that was intended to save ratepayers money, as a directive to purchase McClain.
- Savings for ratepayers can only be realized if OG&E makes prudent and reasonable decisions
  - in the acquisition of capacity,
  - in the dispatch of low-cost coal and high-cost gas fired generating units, and
  - in the support of outside non-regulated investments that tend to raise the cost of electric energy to OG&E ratepayers.
- OG&E had many other opportunities to reduce costs, whether through the issuance of an RFP for capacity or dispatch of available units.
- OG&E s decision to acquire McClain demonstrates the imprudence of OG&E s decision, because OG&E failed to pursue the best-cost alternative for acquisition of 400MW of capacity increases.

OG&E is attempting recovery of several costs spent related to the McClain acquisition, but OG&E does not include these costs in their economic justification for the prudence of the purchase.

| **Condition** | | **Cost** | **Total capacity** | **Annual capacity** | **Comment** |
|---|---|---|---|---|---|
| OG&E purchase price | | $160,212,996 | $401 /KW | $73.36 /KW | |
| +Fixed O&M per OG&E | 0 | | | | not reasonable |
| +Total O&M variable = fixed | $4.4MM | | | $84.85 /KW | DR AG 3.5 |
| +Plant in service LTSA | *$14.5MM* | | | | DR OIEC 21-1 |
| +Plant in service other | *$2.5MM* | | | | |
| Plant in service in rate base | $17MM | $177,818,609 | $445 /KW | $92.13 /KW | |
| Outside acquisition process | $5MM | $182,809,847 | $457 /KW | $94.20 /KW | DR OIEC 13-23e |
| FERC mitigation, asking recovery | $19MM | $201,855,396 | $505 /KW | $102.08 /KW | DR OIEC 11-4E |
| Additional mitigation | $25MM | $226,855,396 | $567 /KW | $112.41/KW | Dr. R.A. Durham |
| +Variable O&M | | | | +$12 /kw | Coffman |

OG&E knew or should have known of these costs before the completion of the acquisition. Clearly, OG&E was not diligent when they excluded the in-service costs, portions of the O&M costs, acquisition process costs, and the complete mitigation cost in its evaluation. Mr. Reed states the evaluation was never performed. Mr. Reed states that the evaluation of alternatives to the purchase of McClain ended before the purchase process was completed. As

36

required by the prudence standard, I examined each of these elements based on the facts and circumstances that existed during the contracting period (September 2002- August 2003).

The deal for the purchase of NRG McClain should have been terminated at any one of the points that OG&E chose to extend the purchase agreement with NRG. OG&E could have terminated the purchase agreement up to July 9, 2004. OG&E identified numerous amendments to the purchase contract after August 18, 2003. These dates were August 18, 2003, Amendment #1 October 22, 2003, Amendment #2 October 27, 2003, Amendment #3 November 25, 2003, Amendment #4 January 28, 2004, Amendment #5 February 13, 2004, Amendment #6 March 16, 2006.

Mr. Coffman bases all comparisons for justification of the acquisition only on the base purchase price capacity of $73.76. His comparison lists unsolicited offers that range from $78.00 to $93.36 / KW. The actual costs of $112.41 are significantly greater than the unsolicited offers. Proper inclusion of the actual costs in the analysis raises the capacity cost of the McClain plant above even the highest of the unsolicited offers for capacity that OG&E listed in Mr. Coffman s testimony.

OG&E did not issue an RFP for capacity and has provided no evidence that the unsolicited offers would be indicative of the offers that would be received in an RFP process. Defined requests for proposals would be expected to result in even lower offers.

The total cost of electricity includes the cost of energy which is determined by variable cost of fuel. Fuel cost is based on gas, oil, or coal and is determined by BTU content of the hydrocarbons. The fuel cost must be added to the capital recovery investment.

There are three major components to the 2001 Stipulation Agreement.

- The Stipulation Agreement was intended to create $75,000,000 in customer benefit.
- OG&E chose to take steps to acquire electric generating capacity of not less than 400 Megawatts to be integrated into the Company s generation system in order to accomplish this savings.
- The company s decision is subject to a prudency review by the Commission for the purpose of determining the level of just and reasonable costs. No commitment was made with respect to acceptance or rejection of the Company s decision to acquire the new generation. The Prudency review includes, but is not limited to, an analysis and review of the alternatives to purchasing the New Generation.

In adding 400 MW of generating capacity, according to its testimony OG&E considered three alternatives of building a new plant, acquiring an existing plant, or contracting for power from third parties.

The PPA option was imprudently discounted by OG&E. OG&E knew, or should have reasonably known, during the acquisition process that the costs were going to exceed the approximately $160 MM purchase price paid directly to NRG. Nevertheless, OG&E continued down the road of purchasing the McClain facility based on that amount, to the detriment of the ratepayers.

37

---

A large portion of the $75,000,000 savings claimed by OG&E is a result of dramatic changes in gas pricing, and the relatively lower cost of energy for the McClain plant, as compared to OG&E s other aging, inefficient gas power plants. However, much of this savings is offset by planned reductions in coal capacity, and in an increase in costs for the PowerSmith contract, after costs of that contract were renegotiated and moved from capacity to energy.

Alternate energy and capacity, including extension of the AES contract as described by Dr. Robert A. Durham, PE, is much cheaper than any gas-fired OG&E plant including McClain. As indicated in its 10-K report, OG&E is reviewing and actively seeking alternatives to purchase power contracts with qualifying facilities and other competitive generation sources.

OG&E s capacity planning assumes that contracts with PURPA QFs would not be renewed, and OG&E s energy needs would be met by building or purchasing power plants. The effect of this would be to increase the cost of electricity to the ratepayers.

As demonstrated in the testimony of Dr. Robert Durham on behalf of AES, OG&E s GenTrader analysis shows OG&E expects to run McClain and decrease coal generation from AES Shady Point and OG&E s own coal plants.

The PPA to use McClain before the purchase was not competitively bid. It is demonstrated in my testimony that McClain is more expensive than other alternative PPA.

There are alternatives OG&E could have employed that would not have caused as substantial increases to the ratepayers. The alternative is purchase of power from PPA at avoided costs or less, such as extending the AES contract. By exercising the option to buy the McClain plant, the ratepayers may be precluded from obtaining electricity from those more competitive plants.

OG&E s relationship with Enogex has placed the corporation in a tenuous position concerning the company s cost of capital. OG&E knew of this risk when they purchased Enogex in 1999, but continued. Lower costs alternatives were and continue to be available.

**Dr. Robert A. Durham, PE**

This case is about providing customer benefit to Oklahoma ratepayers through the provision of low-cost energy. These customer benefits arose out of the Stipulation Agreement entered into by OG&E and the parties to PUD 200100455 and approved by the Commission. That Stipulation Agreement was intended to create customer benefits by reducing OG&E s cost of capacity and energy purchased from third parties. Those savings cannot be realized, however, if OG&E makes imprudent and unreasonable decisions in (1) the replacement of such capacity, (2) in OG&E s dispatch of existing low-cost coal and high-cost gas fired generating units, and (3) in the cost of fuel, transportation and storage from affiliated entities.

OG&E s decision to acquire the McClain facility fails to provide the customer benefits contemplated by the 2001 Stipulation. Whether through the issuance of an RFP for capacity,

38

---

running existing coal units (including AES Shady Point) at higher capacity factors, or the implementation of competitive bidding for all generation, OG&E had many opportunities to reduce costs and provide customer benefits, or at the very least minimize increases in costs of electric energy to Oklahoma ratepayers, without purchasing the McClain facility.

Fuel Costs

The Commission has recognized that competitive bidding will generally result in lower fuel prices and has required utilities to engage in competitive bidding in many instances. OG&E agreed to competitively bid certain fuel services in the 2002 Stipulation Agreement.

Enogex is the major supplier of gas to OG&E s gas-fired generating facilities. For each of OG&E s gas generating facilities, with the exception of the McClain facility, Enogex supplies two services: fuel transportation and storage. Enogex only provides gas storage service for the McClain facility. OG&E s gas costs are between 13% and 20% higher than PSO s, on a $/MMBTU basis, according to FERC Form 1 data for 2004 and previous years.

Although OG&E claims it is providing the $75 MM in customer benefit as specified in the Stipulation Agreement, this is being accomplished primarily through fuel cost savings that would have been experienced anyway and could have been even greater had OG&E s dispatch decisions been weighted more heavily on fuel costs.

OG&E has three sources for low cost coal generation: OG&E s Sooner Plant, OG&E s Muskogee plant and the AES Shady Point cogeneration plant. Sooner and Muskogee use Wyoming coal, while Shady Point uses Oklahoma coal. Coal prices have been very stable under long term contracts with suppliers, while gas is subject to volatile market conditions.

Energy from OG&E s coal plants, and the Shady Point facility, is between $0.01 and $0.02 per kWh. Energy from McClain has ranged in price from $0.04 to $0.08 per kWh. OG&E provided GenTrader runs that show the cost of OG&E generation, fuel and cogeneration cost estimates in years subsequent to the purchase of McClain. Two basic GenTrader runs were provided. The first run shows the modeled OG&E generation costs without the inclusion of McClain, and the second shows the modeled OG&E generation costs with the inclusion of the McClain facility.

The results of these GenTrader runs demonstrate that, after the addition of McClain into OG&E s dispatch system, OG&E s coal units experience a reduced dispatch rate. Specifically, the GenTrader runs show a reduction in the dispatch of low-cost coal units of approximately 300,000 MWHr/yr. Generation from AES Shady Point is modeled as being reduced by approximately 60,000 MWHr /yr.

The reduction in dispatch of low-cost coal has increased the quantity of high-cost fuel needed for gas-fired facilities. The increased fuel consumption essentially eliminates any fuel savings from increased efficiency of the McClain plant with respect to OG&E s other high-cost gas fired generating facilities. This is contrary to Mr. Coffman s statement, on p. 9 of his testimony, that The options category examined the impact on OG&E s existing generation fleet.

39

---

In particular, the new generation would not impede OG&E s ability to maximize the dispatch of low cost coal generation.

Additionally, in PUD 200400564, OG&E claimed it was creating savings by being able to reduce capacity from the PowerSmith facility, in order to maximize low cost coal , including that available from the AES Shady Point facility.

According to OG&E s analysis of the McClain acquisition, AES s capacity factor will be reduced as will OG&E s other low-cost coal fired generating facilities. These base load plants should operate at maximum capacity to provide electricity with minimum marginal costs to the ratepayers. The higher energy costs of the McClain facility should not be used to displace lower cost energy available from existing coal units.

The cost of electricity produced by AES Shady Point is significantly less expensive to the ratepayers than the McClain facility. Taking only the actual capital investment to date (~202MM for McClain), the savings from AES Shady Point contract, as compared to the than equivalent energy and capacity from McClain, using 2004 fuel and capacity costs is $34.7MM, and for 2005 fuel and capacity costs savings are $108.6MM.

The acquisition of McClain did not allow OG&E to terminate the Smith contract (PowerSmith), as OG&E indicates. In the re-negotiated PowerSmith contract, OG&E brought down capacity payments by dramatically increasing energy payments to Smith. If OG&E is allowed to take credit for the reduction in capacity payments to Smith, this credit should be offset by the significant increase in energy costs. My testimony shows that there is a significantly lower level of savings from terminating the Smith Cogeneration contract that OG&E claims.

OG&E increased the effective heat rate they were paying Smith from an effective heat rate of around 2,200 BTU/KWH to a full 10,500 BTU/KWH for the base portion of the contract. With the dramatic increase in marketplace gas costs, the costs of energy have all but offset any claimed savings from capacity.

For the 2 months of May, 2005 and June 2005, which OG&E provided in response to AG2-5, OG&E claims phased-in savings of almost $10.6MM. According to my testimony, actual savings were only $1.7MM.

According to the 2002 Stipulation Agreement, OG&E agreed to competitively bid all new fuel purchases. OG&E awarded a transportation contract to OneOk and storage to Enogex. Neither was competitively bid, according to Mr. Coffman s testimony on pages 15 and 16. Instead, OG&E chose not to continue all of the services that Duke did competitively bid, and arbitrarily awarded the gas storage contract to its affiliate, Enogex. Not only is this contrary to the 2002 Stipulation Agreement, but involved additional costs to the ratepayers due to the addition of the service points between Enogex and OneOk.

OG&E has not lived up to its obligations to FERC in the area of Market Power Mitigation. OG&E had an obligation to create 600 MW of new, additional ATC as mitigation for the anti-competitive result of the McClain acquisition. On May 19, 2005, OG&E reported

40

that this 600MW Bridge had been created. However, on June 15, 2005, there was 0 ATC available into the OG&E control area from competitive generators. This lack of ATC resulted in the loss of significant savings to the ratepayers for the Summer Peak 2005 period.

The estimated cost for upgrades that will fulfill OG&E s obligation to FERC is $25,000,000. OG&E knew, as its own internal documents show, that many of the upgrades would be required, and this cost should have been added into OG&E s analysis of the McClain purchase price.

As a result, my testimony demonstrates the imprudence in OG&E s decision to purchase the McClain facility and the imprudence in OG&E s anticipated use of the McClain facility to the detriment of Oklahoma ratepayers.

**REDBUD ENERGY, LP**

**Kojo S. Ofori-Atta**

Mr. Kojo Ofori-Atta testified on behalf of Redbud Energy LP, and addressed OG&E s transmission upgrades performed to meet the requirements under the FERC s ruling approving of OG&E s Offer of Settlement in the McClain acquisition case. Mr. Ofori-Atta summarized that FERC determined in its December 18, 2003 Order that OG&E s acquisition of the McClain facility, without appropriate mitigation measures could harm competition. FERC approved OG&E s Offer of Settlement, which required the construction of a 600 MW bridge from the Redbud facility into the OG&E control area. OG&E indicated that said bridge would consist primarily of an upgrade to the Draper substation.

Mr. Ofori-Atta s testimony presented Exhibit 2, which provided a list of the upgrades that OG&E did to create the 600 MW bridge. Mr. Ofori-Atta testified that no direct analyses were performed to measure the incremental ATC enabled between Redbud and OG&E as a result of the upgrades listed in Exhibit 2. Mr. Ofori-Atta pointed out however that relevant inferences can be drawn from ATC studies performed by SPP and OG&E for transfers from Redbud to the OG&E control area that show that additional facilities would be required to permit an incremental 600 MW transfer from Redbud into OG&E. In addition, Mr. Ofori-Atta testified that a recent Redbud request for only 440 MW of firm transmission capacity was declined by the SPP for lack of transmission capacity. Finally, Mr. Ofori-Atta testified that another study that was done for OG&E s own internal evaluation of a purchase of the Redbud facility and presents the results of said study for 2008 in Exhibit 3.

Mr. Ofori-Atta stated that the power transfer study was conducted by SPP on a transfer from Redbud into OG&E for the 2004 to 2007 period. The facility overloads that resulted from said study for the years 2005, 2007, and 2010 are presented by Mr. Ofori-Atta in Exhibit 4.
Mr. Ofori-Atta highlighted that for the creation of the 600 MW bridge the most relevant season may be the summer peak season because that reflects the tightest conditions.

Mr. Ofori-Atta also presented Exhibit 5, which he stated shows the facility overloads identified by the OG&E power transfer study. The OG&E study, Mr. Ofori-Atta stated only showed results for 2004, which was different from the SPP study.

Seeing that the two studies show different results, Mr. Ofori-Atta stated that the study conducted by SPP should be the one that should be followed, since SPP is an independent entity without any affiliate generation and is the substantive body that grants transmission service.

Mr. Ofori-Atta continued by stating that Redbud in June 2005 requested 440 MW of firm transmission capacity from SPP to supply power to OG&E under a RFP that Redbud was awarded. Mr. Ofori-Atta testified that SPP denied the transmission request identifying two facility overloads as the cause. He stated that the Silverlake/Division line, one of the overloaded facilities identified by SPP, had been identified in an earlier study conducted for OG&E as being a necessary upgrade. Mr. Ofori-Atta testified that the Redbud transaction to serve OG&E in the summer was to save consumers $4.0 to $4.5 million, according to OG&E statements to the Commission.

OG&E, Mr. Ofori-Atta continued, had informed FERC in May 2005, about a month prior, that the upgrades that created the 600 MW bridge were complete. Mr. Ofori-Atta then presented a list of five possibilities as to why the transmission request by Redbud in June was denied. He stated that one of the possibilities, facilities outages, can be ruled out as Mr. Ofori-Atta pointed out that to the best of his knowledge, no critical outages were reported. Another possibility, that the 600 MW of ATC had been allocated to other market participants, was also ruled out as a possibility based on Dr. Robert Durham s testimony that about 408 MW should have been available. This lead Mr. Ofori-Atta to conclude that without transmission studies that conclusively demonstrate that the upgrades performed by OG&E truly provide the 600 MW bridge, that the upgrades performed so far were inadequate. Mr. Ofori-Atta testified that the absence of the 600 MW bridge harms competition, as stated by FERC, since it was needed to mitigate OG&E s market power. He also stated that OG&E consumers lost $4.0 to $4.5 million in fuel savings because Redbud was denied transmission service to supply power under the RFP Redbud had won.

**Judah L. Rose**

Mr. Judah Rose testified on behalf of Redbud Energy LP that based on his extensive experience and his evaluation of the transaction, the decision-making process that OG&E followed in deciding to purchase the McClain facility was not prudent. Mr. Rose stated that a Present Value of Revenue Requirements ( PVVR ) analysis should have been conducted to determine the least cost option available to the utility to meet customer demand and minimize ratepayer costs. Mr. Rose testified that this type of analysis would systematically compare McClain with term purchase power contracts, short-term wholesale market purchases, demand side resources, new power plants and account for demand variation and operational constraints. Mr. Rose continued by stating that the utility could also use such an analysis to see whether the right amount of capacity was being purchased and if the timing of such capacity addition was correct.

Additionally, Mr. Rose stated that a PVRR analysis would have been consistent with the Joint Stipulation and Settlement Agreement of October 11, 2002 in Cause No. PUD 200100455. Mr. Rose rejected OG&E witness Mr. John Reed s testimony where he states that the utility s expenditures are presumed to be prudent until they are proven not to be. Mr. Rose quoted

42

from the Joint Stipulation that states that the remaining stipulating parties make no commitment with respect to the acceptance or rejection of the Company s decision to acquire the New Generation. Since the McClain purchase was not presumed prudent, OG&E was obligated to provide status reports to the Commission.

Mr. Rose testified that OG&E was conducting similar analysis internally and had all the necessary data to conduct a more thorough analysis. Moreover, Mr. Rose testified that OG&E had obtained SPP market power prices, new unit construction costs from an engineering firm, and had their own projections on electricity demand. The analysis that OG&E conducted was very similar to the required PVRR analysis in several respects, stated Mr. Rose. Mr. Rose indicated that the analysis results in a present value of revenue requirements avoided to the extent that of purchasing power from the market. Also, the option of paying the wholesale power market price for power is a critical alternative and metric. This is because the price would be expected to reflect the impacts of many of the other alternatives that would be systematically analyzed. Mr. Rose testified that for example, new power plants, over the long-term, would tend to cap wholesale market prices since price above costs would encourage more supply. Put another way, he stated that if there were low cost options competing with the McClain purchase, they would tend to depress market prices and decrease the value of McClain. Thus, he continued, wholesale prices summarize the expected economic significance of the other alternatives.

Mr. Rose stated that the analysis that OG&E conducted showed that it was preferred to buy power from the market instead of buying McClain. From Mr. Rose s review of OG&E information, he determined that a present value analysis of the purchase power costs that OG&E had obtained from an outside party showed that these costs were below the cost of purchasing McClain. Mr. Rose testified that the result for a purchase power contract was lower than the purchase of the McClain facility because wholesale power market prices were projected to be very depressed for an extended period of time due to excess capacity.

Mr. Rose stated that OG&E had other ways of determining that wholesale power prices would be low. He testified that the market implied heat rate for 2003 was about 7,728 Btu/kWh and McClain s heat rate is about 7,100 Btu/kWh. Thus, the spark spread is fairly low (628 Btu/kWh), which indicates McClain would have little to contribute in covering OG&E s non-fuel related expenses as presented in the OG&E analysis. So, from this evidence, Mr. Rose s analysis showed that for 2004 the McClain purchase was not economic at the purchase price.

Mr. Rose also testified that there were additional issues to consider, including that OG&E (from a third party consultant) had already been provided an opinion on risk; thus, this consultant had used adjusted discount rates to account for the risk of market uncertainty. Mr. Rose stated that purchase power options would limit risk since they lock in certain aspects of future supply. Mr. Rose called this one of the three principal risk management options, with the other two being buying a plant and building a plant. Mr. Rose testified that all options have risks, so it is important to do a complete analysis and it is important to be explicit about the risk and cost tradeoffs.

Mr. Rose stated that the comparison presented by OG&E witness Mr. Jack Coffman was the closest to a comparison of the PVRR of options. Mr. Coffman on Exhibit JTC-1 compares some of the non-fuel costs of the McClain purchase in $/kW-yr between 2005 and 2014 with seven unsolicited power purchase offers. Mr. Rose pointed out that Mr. Coffman s analysis showed three flaws. The first flaw identified by Mr. Rose was that Mr. Coffman failed to include non-fuel Operation & Maintenance ( O&M ) costs. Mr. Rose presented Exhibit JR-3 that he stated showed the impact of correcting for this flaw. The second flaw Mr. Rose discussed was that the analysis of the capital costs excluded approximately $5 million of acquisition-related costs and $17.5 million of spare parts and other items. Mr. Rose presented Exhibit JR-4 to show the impact of those corrections.

Mr. Rose testified that the specific final cost totals of these items may not have been known to OG&E at the time, but it should have expected these categories of items and included some representative numbers in its analysis. Based on Mr. Rose s analysis, the third flaw is that OG&E did not address the transmission cost undertakings associated with each option, especially with the cost of complying with the FERC predicates for the purchase of the McClain facility. Mr. Rose presented Exhibits JR-5 and JR-6, which show the impacts of this last correction using a low and high estimate for these transmission upgrades.

After all the identified adjustments, Mr. Rose testified that McClain s capital costs increased from $400/kW to between $505/kW to $567/kW, which are higher or close to the three new plant cost estimates Mr. Coffman used on page 6 of his testimony to justify McClain s purchase due to having lower capital costs. Mr. Rose testified that these estimates are $500/kW from internal sources, $534/kW from the U.S. DOE, and $528/kW from Burns and McDonell. Thus, not only does the McClain plant fail the PVRR criterion since the analysis was not done and the purchase power comparison, it also fails the new plant cost test. Mr. Rose then outlines other flaws found in Mr. Coffman s Exhibit JTC-1.

Mr. Rose concluded his testimony by restating that OG&E s decision-making process to purchase the McClain facility was not prudent. He recommended that if the Commission were to approve the McClain purchase based on Mr. Coffman s analysis, OG&E s recovery of costs could be limited to the least cost purchase power option as estimated by the adjustments recommended to JTC-1. Mr. Rose went on to testify that in order to prevent this from happening in the future, the Commission could order that OG&E hold competitive bids for future power needs and that such a process be overseen by the Commission and an independent evaluator to ensure a fair opportunity for OG&E customers is provided.

**Chad Wagner**

Mr. Chad Wagner testified on behalf of Redbud Energy LP. Mr. Wagner stated that his testimony (1) provides a global picture of testimony to be filed on behalf of Redbud, (2) provides background information on the Redbud Facility, (3) describes Redbud s involvement in the OG&E acquisition process, and (4) provides key points for the Commission to consider. Mr. Wagner stated that Mr. Judah Rose and Mr. Kojo Ofori-Atta provide expert testimony on behalf of Redbud that address the prudence of the McClain purchase and transmission related considerations.

Mr. Wagner gave a description of the 1200 MW Redbud Facility, highlighting that it is made up of four identical trains and that it is one of few plants in Oklahoma with SCR

---

technology, which reduces NOx emissions. Mr. Wagner stated that although Oklahoma markets are preferable for Redbud to sell its power, Redbud will sell when economically viable to whoever is a willing buyer and acceptable counterparty.

Regarding the potential acquisition negotiations, Mr. Wagner testified that OG&E never made an offer to purchase the Redbud Facility, and that OG&E did not solicit an offer from Redbud to sell them power. Mr. Wagner testified that Redbud, on its own accord, submitted an unsolicited offer to OG&E, which was reflected on Mr. Coffman s Exhibit JTC-1. Mr. Wagner further stated that OG&E declined Redbud s unsolicited offer because, as was stated in Mr. Coffman s testimony, OG&E did not believe such offer complied with the rate case settlement.

Thus, Mr. Wagner testified, OG&E did not further negotiate with Redbud nor did it seek to better the terms of the unsolicited offer. Mr. Wagner continued by stating that OG&E did not further negotiate with Redbud by emphasizing the fact that Mr. Coffman stated that OG&E intended to comply with commitments it believed it made to the Commission and other parties to the settlement in Cause No. PUD 200100455. Mr. Wagner testified that he believed that OG&E was set on a path to buy the McClain plant and was not considering any other arrangements regardless of the cost savings to customers.

Mr. Wagner stated that it was unclear whether OG&E needed to buy specifically 400 MW of capacity since there were several OG&E resource plans within a year of each other that showed different numbers. Mr. Wagner also testified that OG&E could have saved consumers millions had it been economically dispatching utility and non-utility owned generation.

Mr. Wagner concluded his testimony by stating that Mr. Coffman had stated in his testimony that the Commission was concerned about the company s reliance on purchased power. Mr. Wagner pointed out that the report that Mr. Coffman cites from does not create Commission policy nor does it show that the Commission Staff were not concerned about OG&E s reliance on purchased power.

**FEA**

**Robert J. Conner**

I am Mr. Robert J. Conner a member of the Senior Executive Service and Director of the Oklahoma City Air Logistics Center at Tinker Air Force Base Oklahoma. My prefiled testimony in this cause highlights the economic impact that Tinker has on the Oklahoma economy.

Tinker Air Force Base is home to seven major Department of Defense, Air Force and Navy activities with critical national defense missions, including the Oklahoma City Air Logistics Center, which is the largest Air Logistics Center in the Air Force. The mission of the Air Logistics Center is to sustain weapon systems and deliver ready combat capability to the warfighter through robust product support, purchasing and supply chain management, depot maintenance activities, installation, service and information support for 31 weapon systems, 10 major commands, 93 Air Force bases and 46 foreign nations. The Oklahoma City Air Logistics Center is the Engine Capital of the Air Force, and has prime management responsibility for



---

21,871 aircraft engines valued at more than $31 billion. Approximately 700 engines annually are overhauled at the Oklahoma City Air Logistics Center. Finally, the Oklahoma City Air Logistics Center has cradle-to-grave logistics responsibilities for approximately 24,800 avionics and accessories components valued at over $3.7 billion.

Tinker Air Force Base is the largest single-site employer in Oklahoma with an annual payroll exceeding $1.1 billion. Approximately 26,000 civilian employees, military members and contractors are assigned to Tinker Air Force Base. Tinker Air Force Base impacts the state s economy directly and indirectly. In fiscal year 2004, Tinker Air Force Base executed $4.8 billion in annual contract awards. Of that amount, $793 million was awarded within the state of Oklahoma and $379 million was awarded to small and disadvantaged businesses. Indirectly, base employees and nearly 85,000 retirees have a large impact on the state s economy. Those employees and retirees, as well as nearly 30,000 secondary jobs in the local communities in such fields as housing, food and the services industries have an economic impact on Oklahoma of approximately $939 million per year.

Tinker Air Force Base currently pays approximately $17 million per year for electric utility services. The funds used to pay for utility service are called operations and maintenance funds and these funds are also used to fund military operations and maintenance. Utility bills are considered must pay bills, meaning they are among the first requirements funded and paid by the government. Any cost avoidance or reduction in costs Tinker realizes on utilities ensures funds could be utilized elsewhere for essential military operations and maintenance.

**WAL-MART**

**Jess Galura**

My name is Jess Galura and I am a Senior Regulatory Analyst for Wal-Mart Stores East, LP ( Wal-Mart ). I filed both responsive and rebuttal prefiled testimony in this cause.

I have not previously testified before the Oklahoma Corporation Commission. However, an outline of my background and professional experience is attached to my responsive testimony as Appendix A. Briefly, I am an electrical engineer with over thirty years of experience working with investor owned and municipal utilities, and other stakeholders both on the regulated and deregulated side of the electric utility industry. I have previously testified before the California Public Utilities Commission on cost of service matters and have submitted testimony at the Federal Energy Regulatory Commission as an expert witness in the areas of cost of service and rate design.

Additionally, I was a member of a NARUC task force that revised and included a Marginal costs section to the NARUC s Electric Utility Cost Allocation Manual, more commonly known by the electric utility industry as the Green Book.

Wal-Mart is a large customer of Oklahoma Gas and Electric Company ( OG&E ). Wal-Mart operates over 107 facilities consisting of Supercenters, Discount Stores, Neighborhood



---

Markets, SAM s Clubs, and Distribution Centers in Oklahoma. Sixty three[1] of these facilities receive retail electric service from OG&E under 77[2] service accounts. Wal-Mart employs more than 30,276 associates at our Oklahoma operations alone and purchases over $1.37 billion annually in goods and services from Oklahoma suppliers. Our various facilities in Oklahoma receive service from OG&E under Rate Schedules General Service GS-1, Power and Light PL-1, and Power and Light Time-of-Use PL-1. Wal-Mart also has one account on Large Power and Light ( LPL ). The combined energy that Wal-Mart receives under these rate schedules is approximately 202,760,787 kWh per year.

My responsive testimony addressed the direct testimony filed by OG&E witnesses Kirsch and Walkingstick. I specifically addressed OG&E s proposed cost of service allocations and rate design in the event a rate increase is granted. I made four recommendations:

1. Under OG&E s proposed cost of service allocation, certain customer classes with rates already above their full cost of service would receive significant increases, while other customer classes would continue to receive rates below their full cost of service. I recommended that any approved increase in base rates be allocated among the customer rate classes in such a way that the revenue decreases for customer classes currently already above their full cost of service be reallocated to

other customer rate classes based on their respective rate base ratios. This recommendation is set out in Exhibit 1, Alternative #1, attached to my responsive testimony.

**2.** As an alternative, in addition to no customer rate class receiving any rate decrease, no customer class should get an increase. I recommended that the Commission follow OG&E s recommendation to put the Large Light and Power Class and the Municipal Pumping Class at their full cost of service rates before reallocating the revenue decreases to the remaining customer rate classes based on their respective rate base ratios. This recommendation is set out in Exhibit 1, Alternative #2, attached to my responsive testimony.

3. I concluded that OG&E s recommendation to flatten the rate design for all of the customer rate classes is not supported by the way the OG&E system is operated and the Marginal Cost study presented by OG&E witness Dr. Laurence D. Kirsch. Therefore, I recommended that this proposal be rejected by the Commission.

4. I also recommended that the Commission reject OG&E s proposal to increase the power factor requirement from 80% to 90% in order for customers not to incur a penalty under Service Levels 1 and 2.

---

[1] Revised figure.

[2] Revised figure.

47

---

My rebuttal testimony addressed the responsive testimony filed by the various parties on the issues of cost of service allocation and rate design. Specifically, I addressed the responsive testimony of Edwin C. Farrar, CPA, filed on behalf of the Commission Staff. I also addressed the cost of service allocation and rate design testimony filed by Glen E. Gregory on behalf of the Oklahoma Industrial Energy Consumers ( OIEC ).

Mr. Farrar s testimony focused more on expanding OG&E s load management programs than designing rates for the various customer classes. While I generally agree with Mr. Farrar as to the desirability of implementing or expanding load management programs, I do not support Mr. Farrar s specific recommendations.

My rebuttal testimony recommends that time-of-use energy rates not be limited to industrial customers under the LPL Service Level 1 and 2 rate schedules as recommended by Mr. Farrar, but should be made available to all commercial and industrial customers under all the PL TOU and LPL TOU rate schedules. Properly designed time-of-use rates could be developed using OG&E s marginal cost study results. The resulting rate structure and level of charges should provide sufficient incentive to customers without the need to provide demand side management credits as recommended by Mr. Farrar. I believe that Mr. Farrar s recommendation would be very complicated to implement and could lead to a substantial administrative burden to the utility and to the Commission staff.

I also do not support Mr. Farrar s recommendation for funding his recommended changes to OG&E s load management programs. The funding mechanism recommended by Mr. Farrar will generate substantial funds for load management programs, but without specific guidelines on how the funds will be used by OG&E or its customers. With an estimated retail sales level of 20,484,804,029 kWh for the test year, Mr. Farrar s recommended funding level of $0.003 per kWh could generate a total of $61,454,412. This is equivalent to about 4.4% of total base rate revenues, almost doubling the rate increase requested by OG&E in this proceeding.

As an alternative, my rebuttal testimony recommends that the Commission order OG&E to develop demand side management ( DSM ) programs that require the utility to track its retail customers DSM-related charges (i.e., the $.003/kWh funding suggested by staff) so that they can be made available for use by the customer for DSM investments as authorized by the Commission. I suggest labeling this program a Customer Self-directed Demand Side Management Program ( CSV-DSM ). I further suggest that the Commission order OG&E to set-up a Collaborative Working Group to work on the details of the CSV-DSM program.

Wal-Mart believes that Customer Self-direction is inherently more equitable for DSM funds collected from customers to be used by those customers in their own facilities, rather than to be used for the benefit of other customers not participating in these efforts.

I also do not support Mr. Farrar s recommended method of recovering transmission related expenses through the Fuel Adjustment Clause ( FAC ). Transmission related expenses are considered fixed or demand related cost by the electric utility industry. Collecting these expenses through the FAC is equivalent to re-classifying these costs as variable or energy related costs, which results in over-allocating costs to high load factor customers.



---

Glen E. Gregory filed extensive testimony on cost of service allocation and rate design on behalf of the OIEC. Essentially, Mr. Gregory rejects OG&E s proposed cost of service allocation methodology and recommends a new allocation methodology. Mr. Gregory recommends allocating the costs from OG&E s generating plants using the base, intermediate and peaking methodology through what he calls a modified Average and Excess Demand Non-Coincident Peak ( AED-NCP ) methodology.

Mr. Gregory also recommends a second alternative allocation methodology in the event that the Commission chooses not to adopt his first recommendation. He then recommends a third alternate methodology in the event the Commission chooses not to adopt his first or second recommendations. Mr. Gregory also recommends a number of changes to OG&E s proposed rate design.

It appears that both OG&E and OIEC agree that an AED-NCP methodology is appropriate for allocating demand related costs for the OG&E system. The only difference between the two proposals appears to be the summer months considered and the appropriate value of customer Non-Coincident Peak ( NCP ) used in the allocation. The two proponents are discussing the same system and should work collaboratively to determine the appropriate months and NCP values to use in the cost of service study and should conclude with the same results.

I do not support Mr. Gregory s proposed method of allocating fuel or energy related costs from the coal and natural gas plants with the same AED-NCP allocation factors used to allocate demand related costs. Instead, I recommend that energy-related costs be allocated to each customer rate class on the basis of the respective customer rate class contribution to the energy consumed during each of the time-of-use periods used in designing the rates. This is the best and most appropriate way for the energy related costs to be appropriately allocated to the customer rate class that causes the utility to incur that cost.

I also do not support Mr. Gregory s second alternative recommendation. This alternative suggests that Mr. Gregory has no strong conviction on the appropriate method to conduct a cost of service study for the OG&E system. His second alternative recommendation seems to indicate that as long as the end result shows a rate reduction for the LPL Service Levels 1 and 2 classes, it will be acceptable.

I also do not support Mr. Gregory s third alternative recommendation. Regardless of the allocation methodology adopted for allocating fuel and purchased power cost, the energy consumption of each customer rate class should be adjusted with the appropriate loss factors before using them for allocating cost. Mr. Gregory s third alternative recommendation fails to make this adjustment.

With regard to rate design, it is my understanding that Mr. Gregory is recommending that OG&E s energy rates be designed to reflect loss factors by voltage level, time-of-day when energy is consumed, and seasonal cost patterns. Although I agree with the desired end result on the final rate structures, I disagree with the method in which Mr. Gregory develops the rates. Mr. Gregory and I are both supporting the use of time differentiated rates in developing the energy charges. However, while he is recommending the use of the AED-NCP to allocate the costs to each time period, I am recommending use of the energy consumed by each customer rate



class to allocate such costs to each time period. I believe that this proposed methodology is more appropriate than what Mr. Gregory is recommending.

Because none of the parties supported OG&E s requested rate increase, and some support significant rate decreases, my rebuttal testimony also discusses how a rate decrease should be handled under my proposed revenue allocation principles. My rebuttal testimony recommends that should the Commission adopt a rate decrease in this proceeding, it should be allocated only to the customer rate classes whose rate of return is higher than the average authorized rate of return in this proceeding. This step is necessary in order to align each customer rate class toward their true cost of service.

**OIEC**

**Mark E. Garrett**

**Plant in Service** The OIEC proposes updating the Plant in Service and related Accumulated Depreciation accounts through June 30, 2005, six months from test year end. This approach includes in rate base all projects actually completed and in service within six months of the test year. Likewise, all changes in the Accumulated Depreciation accounts are also recognized. In ONG s recent rate case Cause No. PUD 200400610, the ALJ adopted this approach, with CWIP projects at the later cut-off date specifically excluded. My adjustments are calculated by comparing the Company s requested level of Plant in Service and Accumulated Depreciation to the actual balances in these accounts at June 30, 2005. The Plant in Service adjustment reduces rate base by $31,790,359. The adjustment to Accumulated Depreciation reduces rate base by $37,512,964. Finally, an adjustment of $929,968 is made to remove plant held for future use in OG&E s pro forma rate base.

**Cash Working Capital** The Company requests an increase to its total company rate base for cash working capital of approximately $38.6 million. OG&E s lead-lag study has obvious errors that must be corrected. These errors consist of (1) the inclusion of non-cash items such as depreciation in the allowance calculation formula and (2) the inclusion of common equity in the calculation. This Commission has already heard and decided these issues. In ONG s 1991 rate case, Cause No. PUD 1190, the final order states:

The Commission finds . . . noncash cost of service should not be included in ONG s CWC allowance calculation formula. The Commission finds the arguments of Staff and the AG persuasive on the issue and finds that if noncash cost of service items were included . . . ONG s CWC formula would be overstated.

The Commission finds . . . that ONG s return on common equity should not be included in ONG s CWC calculation . . . to include such an item in ONG s CWC would compound ONG s stockholder s equity return and overstate ONG s needed CWC.

50

8-K

The approach used by this Commission is the generally accepted rule. In his treatise, *The Process of Ratemaking*,[3] Leonard Saul Goodman discusses the working capital allowance at length. In Volume II, page 829, the treatise states the following with respect to non-cash items: A cardinal principle of the working capital allowance is that it should exclude non-cash expenses, such as depreciation, deferred income taxes, and return on common equity, among others.[4] With respect to depreciation specifically, Goodman further states: Depreciation expense must be excluded. Even if there is a lag in recouping investment from the time service is rendered to the time the customer pays for the service, there is no basis for adjusting working capital studies for depreciation. Capital markets are aware of any lag involving depreciation expense recovery, and adjust accordingly.[5] The Company s corrected lead-lad study can be seen at W/P MG-2. The recalculated Cash Working Capital Allowance is $10,069,567. Therefore, the Company s pro forma CWC is reduced by $28,538,242.

**Coal Inventory** In this application, the Company seeks an increase of $10,557,792 to its test year end coal inventory balances. Company witness, Mr. Holloway explains that this adjustment is necessary to achieve a targeted 75-day burn level for coal levels. From a review of the inventory levels during the 2004 test year and the six month period following test year end, over the past year and a half, the Company has actually maintained an average inventory level of about 53 days. The Company points to a February 2004 fire at the Sooner plant that interrupted deliveries and caused inventory levels to sag for a time. However, that event occurred over a year and a half ago and the Company s inventory levels returned to the levels maintained before the event by June of 2004, and have not increased above that level through June of 2005. I recommend that the thirteen (13) month average of actual inventory levels at June 30, 2005 be used. The 13 month period ending June 30, 2005 (June 2004 June 2005) avoids the claimed inventory interruptions associated with the February 2004 *force majeure* event and includes the statutory six month post test year period. The adjustment needed to reflect this 13 month average level at 6-30-05 is a $10,509,271 rate base reduction.

**Fuel Oil Inventory** The Company proposes an increase of more than 50% in its fuel oil inventory levels, from 10,227,927 gallons to 15,688,644 gallons, at a cost increase of $4,641,609. However, a review of recent history shows that the company does not actually maintain an oil inventory at these levels. The Company requested a similar increase in its oil inventory levels in its 2001 rate case, for the same reasons cited in this application: as a physical hedge against gas price volatility. However, the Company never implemented the increases, even though there was nothing in the stipulation or final order in that proceeding that precluded them from doing so. I believe that if the increased inventory levels were necessary and prudent, the Company would be maintaining them now. I have recommended that the thirteen (13) month average of actual inventory levels at June 30, 2005 be used. The thirteen month average at June 30, 2005 (1) includes the statutory six month post test year period, (2) uses the most recent

---

[3] 1998, Public Utility Reports, Inc.

[4] Goodman cites cases in Iowa, Utah and Illinois. Texas, Arizona, Nevada, Kansas and Oklahoma, among many others could have been included in his list. For example, in Texas, the commission rules specifically exclude non-cash items, including depreciation, deferred taxes and return on equity from the calculation.

[5] Quoting from Re Illinois Bell Tel. Co. 156 PUR4th 121, 222 (Ill.CC, 1994); and see Re Central Ill. Light Co., 159 PUR4th 1, 21-22 (Ill.CC, 1994).

51

data available, (3) yields a result equivalent to the balances at test year end, and (4) is the best representation of the inventory levels actually maintained by the Company. The adjustment needed to reflect the actual average levels at 6-30-05 is $4,647,951.

**Materials and Supplies** The Company s year-end balance in this account appears to be unusually high. Rather than make the usual adjustment to the 13-month average in this account, the Company instead included the year-end balance in pro forma rate base. I am proposing to adjust the Company s requested level to the 13-month average in this application. The adjustment needed to reflect 13-month average Materials and Supplies balance is $5,216,927.

**Accumulated Deferred Income Tax** This adjustment updates the Company s Accumulated Deferred Income Tax ( ADIT ) balances to the 6-30-05 levels. This adjustment is necessary to give effect to the known and measurable increase in the deferred tax balances that occurred within six months of test year end. When additions to the investment levels in Plant in Service are recognized through the six month period following test year end as requested by the Company in this cause off-setting decreases in the investment levels related to Plant in Service such as Accumulated Depreciation and ADIT must also be recognized. This standard adjustment was recognized and accepted by the ALJ in her recommendations in the recent ONG rate case proceeding.[6] The adjustment to reflect ADIT balance at June 30, 2005 is $18,951,932.

**Prepaid Pensions** I propose to reduce the Company s rate base by the balance of its Prepaid Pension Account and increase operating expense by an amount equivalent to a cost of debt return on this balance. The balance in this account is the accumulated difference between the SFAS 87 calculated pension costs each year and the actual contributions made by the Company to the pension fund. The minimum required contribution level for the Company over the past five years has been zero. Thus, the Company s recent contributions have been discretionary. The Company has been contributing more than the minimum required contribution level and even more than the SFAS 87 calculated cost level because the Company s estimated pension obligation has been greater than the estimated value of the plan assets in recent years. The excess contributions made by the Company were intended to bring the value of the plan assets more in line with the Company s estimated pension obligations. A rate base return includes a substantial profit component while a cost-of-money, or long-term debt return, does not. The Company should not be allowed to earn a profit on the excess discretionary contributions it makes to the pension fund above the SFAS 87 levels. It should also be noted that Long-Term Debt in the Company s Capital Structure is being reduced by the amount of the Prepaid Pension balance, as requested by the Company. The adjustment to decrease pro forma rate base for prepaid pension costs is $67,156,464. The adjustment to increase expense for long-term debt return on the prepaid balance is $4,009,241.

**Alternate Financing on Working Capital Balances** The Company has access to and uses substantial amounts of short-term debt to finance its working capital operations. Assets financed with long-term debt and equity, such as Plant in Service, should be included in a utility s rate base. However, assets that are actually financed with short-term debt should not be included in the Company s rate base unless short-term debt is included in the Company s capital structure. It would be inappropriate to provide the Company with a full rate base return of approximately 8%

---

[6]The ALJ s recommendations were adopted in the Commission s Final Order.

52

- 9% on assets which the Company finances at short-term borrowing rates of 2% - 4%. The average balance outstanding during the six-month period after test year end was $143,700,000. The average monthly interest rate on short-term debt at 6-30-05 was 3.181%.

The amount of short-term debt in excess of a utility s CWIP projects is considered available for working capital requirements. At 6-30-05, OG&E s CWIP balances totaled $91 million. This means that about $52.7 million of the Company s average short-term debt outstanding would be available for working capital requirements. The Company uses a combination of short-term debt, long-term debt and equity to finance its working capital requirements. Therefore, a reasonable allocation of short-term debt to the working capital balances is needed. The Company can finance all of its Cash Working Capital requirements with short-term debt, and a majority of its other working capital requirements as well. A reasonable allocation of short-term debt to the working capital balances would be to assign 100% of the CWC allowance and 50% of the other working capital accounts to short-term financing. The total amount of short-term debt applied to working capital accounts using this allocation would be about $49.7 million, well below the calculated $52.7 million available for working capital needs. The adjustment to remove the excess portion of working capital from rate base is $52,210,815, and the adjustment to include short term interest on the working capital balance is $1,660,826.

**Labor Expense** OG&E proposes an adjustment to increase labor expense for estimated additional employees the Company planned to add to the workforce after test year end. This adjustment increases labor expense by $3,195,850 and payroll taxes by an additional $227,155. The company s workforce did not increase by the number of new employees anticipated. Further, the Company s methodology for quantifying any associated increase in labor costs is inappropriate for ratemaking purposes because it looks at potential increases to the labor accounts associated with hiring new employees without recognizing decreases to the accounts that occurred over the same period of time. Instead, I am proposing that the actual increase in the payroll levels at June 30, 2005 be included in rates rather than the estimated increase proposed by the Company. Using data provided in response to OIEC 2-2, I annualized the payroll levels at 6-30-05. I then compared the 6-30-05 annualization with the Company s annualization at test year end to determine the actual additional increase in payroll costs that occurred from test year end through 6-30-05. Adjusting Labor Expense to reflect the actual increase in that account results in a reduction to pro forma operating expense of $2,738,498.

**Pension Expense** The Company s proposed increase over test year expense levels is based upon estimates provided by the Company s actuarial firm. However, data provided in response to OIEC 7-8 and 7-9 indicates that the actual levels of expense for 2005 for both pension and OPEB costs are lower than initially predicted, and that the level of pension and OPEB costs will drop substantially over the next few years. It would be inappropriate to set rates to recover an estimated expense level that is higher than the expense level the Company is actually incurring and substantially higher than the level the Company will experience during the period prospective rates are in effect. My adjustment to pension expense and other post-retirement employee benefit (OPEB) costs reduces the Company s requested increase for these costs to the actual level of increase that has occurred in 2005, resulting in a reduction to pro forma pension expense of $1,474,529, and a reduction to pro forma OPEB expense of $825,293.

**Executive Retirement Income Restoration Costs** OG&E provides a restoration of retirement income to pension plan participants whose benefits are subject to limitations under the Internal Revenue Code. In general, retirement benefits on compensation levels in excess of the $205,000 limitation are paid through the restoration plan. I am recommending that these costs be removed from pro forma operating expense. For ratemaking purposes, shareholders generally bear the additional costs associated supplemental benefits to highly compensated executives of the company. The adjustment to remove retirement restoration plan costs is $912,749.

**Executive Incentive Compensation** A review of the Company s incentive plan indicates that the executive incentive plan is based almost solely on financial performance measures. On two separate occasions this Commission has addressed the issue of whether to include incentive compensation in rates. On both occasions, the Commission excluded the entire amount of incentive payments made during the test year. In its order in Cause No. PUD 91-1190, this Commission addressed ONG s employee incentive plans, the Gainshare Plan and the Executive Stock Performance Plan. The Commission disallowed the entire cost of both plans, based upon the arguments of Staff and the Attorney General that the plans were designed to increase corporate earnings. More recently, in Cause No. PUD 04-610, after a hearing on the merits, the ALJ disallowed the entire cost of both the executive and non-executive payments.[7] In this case, I recommend excluding 100% of the executive incentive payments for ratemaking purposes. This recommendation does not have a detrimental impact on the Company. In those years when financial performance measures are not achieved, incentive payments are not made. As a result, the Company suffers no financial harm when it does not collect through rates a payment it does not make. However, in those years when earnings do increase and financial performance measures are achieved, then, additional compensation will be paid to the employees. However, funding for these payments will have been made available to the Company through its increased earnings. The adjustment required to remove executive incentive payments is $5,175,634.

**Non-executive Incentive Compensation** The costs associated with non-executive incentive compensation plans are typically excluded from rates for the following reasons: (1) Payment is uncertain, conditioned upon meeting some predetermined goal, and therefore is inappropriate for setting prospective rates; (2) many of the factors that impact earnings, for example hot summers and customer growth, are outside the control of most company employees and have limited value to the customers; (3) stockholders assume none of the financial risks; (4) incentive payments based on financial performance measures should be made out of increased net earnings that trigger the payments; (5) incentive payments embedded in rates shelter the utility against the risk of earnings erosion through attrition. My analysis shows that OG&E s incentive compensation plan is weighted roughly 50% toward financial performance measures and 50% toward business measures related to safety.[8] Therefore, I recommend a 50/50 sharing of these costs between shareholders and ratepayers. The proposed adjustment to remove one half of incentive plan costs for non-executive employees from pro forma operating expense is $3,313,642.

**Legislative Advocacy** Traditionally, the costs of legislative advocacy are not included in operating expense for ratemaking purposes because the political interests of a regulated utility that enjoys a monopoly franchise within the state can be quite different from the interests of the

---

[7]This recommendation was adopted in the Commission s Final Order.

[8]In the recent ONG case, 100% of non-executive incentive payments were excluded because they were based upon financial performance measures.

54

company's captive ratepayers. It would be unfair to require ratepayers to fund the lobbying activities of corporate executives whose duty of loyalty is clearly owed to the corporation and its stockholders. The adjustment required to remove legislative advocacy expense is $505,623.

**Outside Services Expense** OG&E s outside services expense level appears to be unusually high during the test year. My adjustment normalizes the test year level to the average level of expense incurred over the past five years, resulting in a reduction of pro forma outside services expense of $518,921.

**Bad Debt Expense** I propose an adjustment that reduces the Company s requested level for bad debt expense to the actual level of write-offs experienced for the twelve month period ending 6-30-05, six months after test year end. This is the most up-to-date data available, and the best representation of the new level of Bad Debt expense the Company has been able to achieve through its recent efforts to reduce bad debt losses. This results in a $721,631 reduction of pro forma bad debt expense.

**Storm Damage** OG&E proposes a pro forma adjustment to normalize storm damage costs to a four-year average level because storm damage costs were unusually low during the test year. I agree that using an average to normalize storm damage expense is appropriate, since these costs can fluctuate significantly from year to year. However, because of these potential significant fluctuations, I believe a longer average period should be used. I recommend using a more comprehensive 7-year average. Based on this average, OG&E s pro forma storm damage expense is reduced by $1,551,194.

**Regulatory Expense** OG&E seeks to include in pro forma regulatory expense a three year amortization of the costs incurred in the Smith Cogeneration litigation during the test year, in the amount of $412,914, and a requested increase in Arkansas jurisdictional regulatory expense in the amount of $133,000. The Company s request to recover past costs in future rates is retroactive in nature. Just as a utility is not required to disgorge earnings in excess of its authorized return, it is neither permitted to amortize into future rates costs that it believes its prior rates were insufficient to cover. If the Commission were to authorize such a request, it would set a poor public policy for regulation in this state. The adjustment to remove these costs reduces Regulatory Expense by $545,914.

**Marketing Expense** This adjustment removes $709,408 from pro forma operating expense for the marketing costs of the Company. In Oklahoma, Advertising costs are statutorily excluded for ratemaking purposes. The non-discretionary language of 17 O.S. § 180.1 states: Advertising expenses shall not be included by a public utility in its operating expenses for ratemaking purposes. The company has made no showing that its Demonstration and Selling costs meet any exception to the statute. Ratepayers, as a whole, do not benefit from promotional advertising expenditures which are often designed to increase electric sales volumes through the installation of electric appliances. An increase in electric sales volume from customers switching to electric appliances conversely causes a decrease in gas sales volumes. This costly competition for load merely shifts revenues from one utility to another. From a ratemaking perspective, ratepayers should not be charged with costs of customer churning that primarily benefit the shareholders.

55

---

This Commission specifically addressed the ratemaking treatment of expenditures for promotional advertising and marketing campaigns and has disallowed these types of marketing and advertising costs.[9] Recently, in PUD 04-610, the ALJ again disallowed all of ONG s demonstration and selling costs in accounts 99110 and 99120. My adjustment in this case removes all of OG&E s costs in 99110 and 99120, consistent with the Commission s previous orders. The impact of the adjustment is $709,408.

**Depreciation Expense** The Company s pro forma depreciation expense was calculated using its new proposed depreciation rates applied to Plant in Service balances at test year end and CWIP projects the Company estimated would be in service by 6-30-05. Using data provided in response to OIEC 7-5, my adjustment applies OG&E s new depreciation rates to the Company s actual Plant in Service balances at June 30, 2005, rather than the anticipated levels utilized by the Company in its proposed adjustment. This reduces pro forma depreciation expense by $ 1,135,638.

**Depreciation Expense for McClain Assets** I recommend that the Company use a longer average service life (ASL) for the assets of the McClain plant that are not covered under the Long Term Service Agreement ( LTSA ). The LTSA covers certain parts of the high efficiency gas combustion turbines that are being replaced over shorter lives of 1, 3, 4, 6 and 7 years. Under the Company s proposal, the rest of the plant is being depreciated over a 27 year life. When combined the plant s annual depreciation expense reflects a recovery period of only about 16 years. This is far too short when compared to the Company s other gas plants or to the depreciation lives of other combined cycle plants.

To correct this, I recommend a service life of 43 years for the assets not covered under the LTSA. This provides annual depreciation recoveries for McClain that reflect an overall plant life of 20 years. This is still far shorter than the plant lives of OG&E s other gas plants and shorter than the depreciation lives of other combined cycle plants on the market.[10] The adjustment to restate McClain depreciation to reflect an overall 20 year plant life reduces pro forma depreciation expense by $ 1,983,632.

**McClain Regulatory Asset Amortization** The final order in OG&E s last rate case, Cause No. PUD 01-455, gave the Company the authority to defer, for the period of one year, the costs associated with owning and operating a new generation facility, including operating and maintenance costs, depreciation and a return on the investment. OG&E acquired the McClain plant in July of 2004. In this application, the Company has included in rate base a regulatory asset in the amount of $25,860,809 for the costs associated with owning and operating the plant for a twelve month period from July 2004 though June 2005. The Company is seeking a three year recovery of these costs all from the Oklahoma ratepayers at an annual amortization of $8,620,270.

In responsive testimony I addressed only two issues with respect to the Company s proposed treatment of the amortization: (1) the request to recover the entire regulatory asset over a three year period and (2) the request to recover the entire amount of the regulatory asset from the Oklahoma ratepayers. I stated that a recovery period of three years is an unreasonably short recovery period that creates an unnecessary hardship on the ratepayers at the worst possible time

[9]*See* PUD 91-1190 and PUD 04-610.

[10]The average service life of OG&E s other gas plants is 51 years. The average service life for other combined cycle plants appears to be from between 27 to 32 years.

56

when fuel prices are at historically high levels. For ratemaking, since costs should follow benefits, a longer recovery period is appropriate. To the extent there are benefits that derive from the McClain purchase, these benefits should inure over the entire life of the asset.

From a policy perspective, a longer recovery period makes sense because gas prices are extremely high, and there exists the very real possibility that prices will remain high or climb even higher in the near future. While the utility is financially indifferent to the high cost of gas, ratepayers are not. These high prices impact them directly and profoundly. In my opinion, this is not the time for this Commission to layer onto already high utility bills additional amounts for an unnecessary accelerated recovery period for a regulatory asset. As such, I recommended a period of ten (10) years, which strikes a reasonable balance between the two potential extreme positions: the three year period recommended by the Company and the twenty-seven year life of the plant. The adjustment required to amortize the McClain regulatory asset over ten (10) years is $6,034,188.

**OIEC s Rebuttal Position: McClain Regulatory Asset Amortization** In rebuttal testimony, I propose a revised recommendation on the issue of the McClain Regulatory Asset, based on the responsive testimony of Attorney General Witness, Mr. Scott Norwood. Mr. Norwood points out that the Company is not consistent in its treatment of the McClain acquisition for purposes of applying the provisions of the Settlement Agreement in Cause No. PUD 01-455.

In Paragraph 2, the Settlement Agreement states that OG&E is obligated to credit its customers $25 million if the Company has not acquired new generation by January 1, 2004. In paragraph 3, OG&E is given the right to accrue a regulatory asset for the costs to operate the new plant for a period not to exceed twelve months subsequent to the acquisition and initial operation of the generation facilities described in paragraph 2 of this Joint Stipulation.

In the instant cause, OG&E claims that the acquisition and initial operation of the plant began on July 9, 2004, and that OG&E is entitled to accrue a regulatory asset for a twelve month period subsequent to that date. However, in Cause No. PUD 200400004, OG&E claimed that it effectively owned the plant under the terms of a master Power Purchase Agreement ( PPA ) entered into on July 24, 2003. In its brief filed with this Commission in that cause, the Company stated:[11]

The McClain facility is now included in OG&E s generation resources, by virtue of OG&E s rights under the PPA. OG&E is entitled to at least 400 megawatts of output of the unit at all times, the PPA allows OG&E full rights to dispatch the unit, and OG&E treats it as a part of its generation portfolio in determining which of its units it would be most economical to run. Notwithstanding OG&E s lack of formal legal title, OG&E already has acquired the unit under any reasonable interpretation of the term in the context of the Stipulation, with the result that the savings contemplated by the Stipulation are being enjoyed today by OG&E s customers. (Emphasis added).

---

[11]Answer of OG&E in Opposition to Motion to Dismiss, page 5.

57

---

OG&E claimed in PUD 04-004 that it effectively owned the plant under the terms of the PPA because according to the Settlement Agreement, OG&E was obligated to credit its customers $25 million if it had not acquired new generation by January 1, 2004. To avoid the $25 million payment obligation, OG&E claimed, and the Commission agreed, that the Company had effectively acquired the plant in the context of the Stipulation under the terms of the PPA. However, this position is not consistent with the position OG&E takes in this case. The Company cannot on the one hand claim that for purposes of the ratepayers $25 million credit calculation it acquired the plant on July 24, 2003, and then on the other hand claim that for purposes of the shareholders Regulatory Asset calculation it acquired the plant on July 9, 2004, one year later.

In responsive testimony, I allowed full recovery of the Company s accrued balance of $25.8 million. I accepted the later acquisition date of July 9, 2004, because this date was consistent with the OIEC s position in PUD 04-004, that the Company had not effectively acquired the plant earlier under the terms of the PPA. Mr. Norwood is right, however. The test here is not what the OIEC believes with respect to the acquisition date but rather what the Commission ruled with respect to the acquisition in PUD 04-004.

If the Company had effectively acquired the plant under the terms of the PPA for purposes of the $25 million credit calculation, then it could not have acquired the plant at a later date for purposes of the regulatory asset accrual. If the Company effectively acquired the plant under the PPA, then it acquired the plant on July 24, 2003, when it entered into the PPA agreement. For the twelve (12) month period after that date, from July 24, 2003 to July 9, 2004, the entire costs of the PPA were flowed through to ratepayers through the FCA. As such, the Company has fully recovered the entire cost to operate the new plant for the twelve (12) month period after acquisition and initial operation of the plant. The impact of this recommendation removes OG&E s requested $25.8 million regulatory asset from rate base and reduces operating expense for the entire amount of the proposed $8.6 million amortization of the balance. The resulting additional decrease in rates is approximately $4.979 million.

**Holding Company Allocation** The Company seeks to include approximately $28.9 million in rates for corporate overhead costs allocated to OG&E. My adjustment reduces the amount of corporate overhead costs allocated to OG&E by approximately $3.9 million based on a revised allocation methodology.

The Company currently uses a three factor allocation formula that is a variation of the Distrigas method ( Distrigas ), based on the average of the following three factors: (1) gross plant, (2) net operating revenues, and (3) payroll expenses. This formula does not adequately allocate corporate overhead costs between OG&E and its unregulated affiliate, Enogex. Instead, it causes a disproportionate amount of the corporate overhead to be allocated to the regulated utility.

The Commission has not previously addressed this issue. It is appropriate at this time for the Commission to consider an allocation formula that apportions corporate costs based upon a more reasonable cost-causal connection. Two of the criteria currently used are not relevant or appropriate for allocating corporate costs such as salaries and expenses of senior management, salaries and expenses of non-senior management, board of director fees and expenses, independent

58

auditor fees, expenses for the investor relations function, corporate legal expenses and other related charges, and other general and administrative costs.

There is little, if any, causal connection between these corporate overhead costs and the level of payroll expense at each business unit. In fact, for many of the costs outlined above, the opposite would be true. Less, not more, time and attention of senior and non-senior management would need to be devoted to a business unit that is already stocked with sufficient, competent management personnel, such as OG&E. The same could be said of audit costs, legal expense, and investor relations. The more competent and high level the personnel is that resides at the subsidiary level, the less need there will be at the corporate level to provide the services these individuals perform. Clearly, the time and attention of upper management is focused much more proportionately towards the business units with the greatest potential for profit than toward the company with the greatest payroll expense. Likewise, Gross plant is an ineffective allocation factor because it ignores the significance of non-plant assets toward business risk and profitability. Business units with very little steel in the ground can have significant other assets that contribute substantially to both business risk and profit potential.

The criteria for allocating corporate overhead should be a fair reflection of the time, attention and resources management devotes to the business units, more in line with the overall risk and profit potential of the business unit. I recommend the Commission adopt the three factors recommended by Staff in the recent ONG rate case, Cause No. PUD 04-610: (1) total assets (less cash and inter-company receivables), (2) net revenues and (3) earnings before income tax, depreciation and amortization ( EBITDA ). Total Assets should be used in the place of Gross Plant, because corporate management s time and attention is not limited to a focus on Plant in Service alone, but is directed instead toward all of the assets that increase business risk and profit potential. EBITDA is an appropriate measure for corporate allocation because earnings are a strong indicator of profit potential, and thus a strong indicator of where managements time and attention is directed. This is particularly true for OG&E, since managements incentive compensation is based almost exclusively upon financial performance measures. Together, these three factors take into consideration substantially all of the assets, revenues and expenses of the business units.

OG&E s three factor formula results in corporate overhead allocation of 75.95%, while the allocation percentage using OIEC s recommended criteria is 65.63%. The proposed adjustment reduces pro forma operating expense by $3,898,785.

**Gain on Sale of Utility Property** In its application, OG&E did not include the gain on sale of various utility assets in its revenue requirement calculations. These assets were all included in rate base and were sold during the test year for a gain of $3,516,647. The after-tax gain on the sale of these assets was $2,112,219. OG&E stated that the gain was recorded below the line because: (i) customers do not have ownership rights in utility assets, and (ii) the Commission did not allow dry hole cost of the drilling program to be recovered from customers. Therefore, the Company assumed all the risk of the drilling program and is now entitled to any gain from the sale.[12]

The OIEC disagrees with the Company s ratemaking treatment of the gain. First, ownership rights in utility property have no bearing on the ratemaking treatment of gains from the sale of this

---

[12]*See* OG&E s response to OIEC Data Request 2-7.

59

---

property. Second, the dry hole costs of the drilling program are operating costs, not capital costs. It is the ratepayers who bear the risk of capital included in rate base and it is the sale of capital, not operating costs, that generates the gain. So the treatment of operating costs, like ownership rights, has no bearing on the ratemaking treatment of gains.

For ratemaking purposes, gains on the sale of utility property are generally allocated to the ratepayers. The proper regulatory treatment of gains on sales of regulatory assets is actually fairly well settled. In fact, in the case of normal retirements, there is virtually no debate since any gain or loss that may result is routinely passed on to ratepayers through the normal accounting entries to the accumulated depreciation reserve. Disagreements generally arise only in instances when the gain is sizable. In these situations, the utility may lay claim to the gain, or some portion of it, based on notions that ownership of the underlying asset entitles the utility to any gain that may result from its sale. These same notions, however, are noticeably absent when regulated assets are sold at a loss.

A 1994 National Regulatory Research Institute (NRRI) study showed that most states allocated the gain entirely to ratepayers. In fact, of states with a generic policy toward dispositions of gains, only one state allocated the gain to shareholders, and then only if the gain related to an operating unit. In the NRRI survey, the most frequently cited rationale was that gains should accrue to ratepayers for property included in rate base.[13] Clearly, regulatory agencies favor allocating gains on the sale of utility property to the ratepayers, for both depreciable and non-depreciable property. If a Commission were to allow a utility to retain gains on the sale of utility property, it would provide the utility not only with a windfall on the sale but also with an inappropriate incentive to speculate in utility property.

Since the property sold during the test year was all rate base property, ratepayers should be allocated the benefits from its sale. I recommend that the after-tax gain from the sale of utility property during the test year in the amount of $2,112,219 be returned to ratepayers.

**McClain Plant Prudency Adjustment** OIEC witness, Mr. Peaco quantifies the imprudence of the McClain acquisition at $45,000,000. My testimony sets forth the proposed ratemaking treatment of Mr. Peaco s recommended disallowance. This treatment includes the establishment of a Regulatory Liability account, in the amount of $45,000,000, to be amortized to ratepayers over a period of years. In my opinion, a reasonable period of amortization could be a period of from three to ten years. For purposes of filing the OIEC s Accounting Exhibits I propose a five-year amortization period.

The OIEC proposes different amortization periods for the McClain regulatory asset and liability accounts because there are no common characteristics in the costs recorded in the two accounts. The costs in the Regulatory Asset account are costs associated with owning and operating the plant for a one year period before the plant was placed in rates. These costs will arguably benefit ratepayers over the life of the plant. The costs in the Regulatory Liability account, however, are costs that could have been avoided, primarily during the first five years of the project, as set forth in Mr. Peaco s analysis. These costs should be returned to ratepayers during the period of over-charge, the first five years of the project. The adjustments related to OG&E s McClain plant

---

[13] In my direct testimony, I cite examples from three state commissions, (Florida, Michigan, and Massachusetts), addressing the disposition of gains.

60

acquisition imprudence reduce rate base in the McClain Regulatory Liability Account by $45,000,000. The five-year amortization of this amount is $ 9,000,000 per year.

**Overall Recommended Rate Decrease** My adjustments in responsive testimony, along with the cost of capital recommendations proposed by Mr. Thornton and the McClain prudency disallowance recommended by Mr. Peaco reduce the $89 million revenue requirement increase sponsored by OG&E by approximately $120 million. These recommendations would decrease current rates in Oklahoma by approximately $31 million per year.

My recommendations in rebuttal testimony with regard to the McClain regulatory asset would further reduce rates in Oklahoma by approximately $5 million per year, as summarized in the table below:

OIEC RECOMMENDED RATE DECREASE

| | |
|---|---|
| OG&E Proposed Revenue Requirement | $ 89,064,718 |
| Less: OIEC Adjustments Proposed in Responsive Testimony | ($ 120,410,055) |
| OIEC Rate Decrease Recommended in Responsive Testimony | ($ 31,345,337) |
| Less: McClain Regulatory Asset Rebuttal Recommendation | ($ 4,979,728) |
| OIEC Rate Decrease Recommended in Rebuttal Testimony | ($ 36,325,065) |

**Glen E. Gregory**

I am submitting this summary of testimony on behalf of the Oklahoma Industrial Energy Consumers ( OIEC ).

In OG&E s pending rate proceeding, my responsive testimony addressed questions of rate subsidy and fuel allocation between classes and also cost of service and rate design issues. I recommended changes to the class allocation of production plant and the energy produced from the generation plants. My responsive testimony discussed OG&E s rate design objectives and offered alternative rate designs. I discussed the importance of rate design that recognizes that generation costs vary according to the time of use by the customers. I recommended rate design that would allow customers to respond to the fact that generation cost vary according to the time of use. I prepared and supported a customer class cost of service study. This customer class cost of service is based upon the total revenue requirements as supported by the accounting exhibits filed by the OIEC. The results of the cost of service study were used to support changes needed in the allocation of revenues to be collected from the various classes.

**Rate subsidy and fuel cost responsibility:** In the rate section of my testimony addressing subsidy and fuel cost responsibility (beginning on page 6,) I began with Table 1 which shows

61

that from 1995 to 2004 rates paid by industrial customers have increased on a percentage basis much more than rates paid by residential and general service customers. The table also shows that industrial customers rates have increased on a $ per kWh more than the residential customer s rates. This table refutes the claim by OG&E that Large Power and Light Customers are subsidized by other classes. I discussed the link between average cost pricing and the failure to recognize that utilization of the time of use of generation plants by customers affects the cost incurred by the various classes. I developed Table 2 and Table 3 (page 9) to further detail how the use of average cost pricing fails to recognize the differences in the time of use of generation plants.

**Allocation of fuel cost:** Following this discussion regarding the problems of average cost pricing on efficient use of the generation plants, (beginning on page 10), I recommended changes to the allocation of fuel cost that would better recognize the cost-causation caused by differences in use of the generation plants by customers. I recognized that when natural gas prices were much lower, average cost pricing was an acceptable method which did not result in a significant detrimental impact on industrial customers. I reviewed the production allocation method proposed by the Company s AED-NCP and found it to be an acceptable method for allocating production plant so long as fuel cost allocation follows, to a large degree, the assignment of base load plant and intermediate/peaking capacity assignment. I gave recognition to the fact that the base load plants have substantially less fueling cost than the intermediate/peaking plants. I also noted that OG&E had increased the relative demand component assigned to the LPL customers considerably since the last rate case. I made an adjustment to lower this assignment of maximum demand to the LPL class. I also noted that the LPL class load characteristics were basically unchanged since the last rate case. Usage for such class did increase about 10%, approximately the same as the total increase for all customers.

The fueling cost difference of the base load plants vs. the intermediate/peaking load plant was adjusted by assigning some of the fueling cost of the coal plants based upon the customers expected use of the plant. This adjustment was based upon the base load plant capacity assigned by the AED-NCP method. Since the AED-NCP method assigns base load capacity on the annual load factor, it was a simple step to assign some portion of the base load fuel cost by the annual load factor. Classes with better load factors were assigned a greater portion of the low cost fuel than classes that exhibited lesser annual load factors. Approximately 50% of the fuel cost from base load plants was assigned using the annual use method. The remaining 50% or so of the remaining fuel cost was allocated on an average cost basis adjusted for transformation losses. This method results in recognition that the customer use of plant has an effect on fuel cost. The result may seem severe but review of Table 1 shows clearly a cost allocation problem that needs to be addressed. Average cost pricing over the years has resulted in the residential class rates increasing less per kWh consumed than any major class. This has occurred in spite of the fact that the residential class puts the greatest requirement on the peaking plants in summer. This is a situation that will only accelerate and will have an increased detrimental impact on industrial customers. This must be addressed in this case in some manner.

**Alternate Production Cost Allocation Method**: In my testimony I recommended an alternative production cost allocation method. I recommended the use of the 4CP and average production allocators. I recommend this method only if the Commission should decide not to adopt my recommended allocation of fuel costs. This allocation is based on the four peak summer months



---

and better reflects the constraints imposed by the summer peaks on the capacity of the production plants. This method would allocate less fixed costs to customers with smoother usage and lower peaking requirements. This method is again recommended only if the Commission allocates fuel on average cost without recognition of time differentiation of fuel costs.

**Alternate Fuel and Purchased Power Cost Allocation:** My testimony supports OG&E s proposed loss-adjusted FCA rider regardless of the method the Commission decides to use to allocate fuel cost. OG&E s proposed FCA is similar to the FAC used by Public Service Company for many years. This proposed rider recognizes that because of transformation losses, it takes less generated energy to deliver a kWh to a Service Level 1 customer than a Service Level 5 customer.

**Time of Use - Fuel Adjustment Proposal ( TOU-FAC ):** In my testimony, I have proposed a pilot TOU-FAC as a partial solution to the average cost fuel recovery problem. The proposed TOU-FAC applicable to the LPL Service Level 1 and 2 customers would base the FAC in the summer months (June to October) at a higher than average price during the peak hours and at a less than average price during the off-peak hours. This would give the customers a greater incentive to shift load away from peak hours and into off-peak hours. This solution provides those customers with an economic choice. While my initial break in pricing between peak and off-peak hours is small (about $0.005 per kWh), this differential can add up to thousands of dollars for an LPL customer Service Level 1 or 2. This proposal replaces OG&E s proposed elimination of the tail block for consumption over 2,000,000 kWh in the five summer months for LPL customers. The LPL customers would be expected (but not guaranteed) less than average fuel adjustment charge. This would occur because the LPL class as a whole has a more stable and constant demand using energy at all hours. This is not a subsidy. This is recognition that these customers can be expected to use the generation plants more efficiently than the system average. The TOU-FAC would be expected to result in LPL customers moving more of their load to the lesser cost off-peak periods resulting in lower system fuel cost which will in turn benefit all customers.

**OG&E Proposed 90% Power Factor Requirement:** My testimony recommends a more measured approach to OG&E s proposed power factor requirement. The requirement as proposed by OG&E would increase charges to some customers by close to $100,000 annually. I have proposed to increase the requirement from 80% to 82.5% in the second year that tariffs resulting from this rate case become effective.

**OG&E Proposed Military Base Rider ( MBR ):** My recommended rate design would negate the need for such a Rider. Further the goal of growth, expansion and retention of the large industrial customers is of critical importance, as is the growth, expansion and retention of military facilities. If the Commission should approve this rider, OG&E s shareholders should absorb any lost revenues, not OG&E s customers.

**Revenue Allocation Objectives:** This Section outlines the manner in which the accepted objective of revenue allocation to classes should be based. This Section reconfirms my prior testimony that rates that follow cost-causation allow customers to make informed decisions in their use of electricity. It is important that customers receive correct price signals. Rates should

63

---

be developed in a manner that result in customer classes paying the same or similar rate of return. Rates can be mitigated to avoid rate shock for a period of time if necessary.

**Allocation of the Rate Changes:** I have proposed rate allocations that follow the revenue allocation objectives. As can be seen on Table 11 of my testimony, I have mitigated the rate increase needed to bring the residential class to an equal rate of return. I have recommended that the residential rates be moved to 1/2 of the rate of return required in my class cost of service. All other classes in the class cost of service showed return greater than the system average. I have recommend decreases to these classes. The greatest decrease would go to the general service and power and light classes. The Large Power and Light, Service level 2 class would also receive a reduction in rates. This allocation of course would change should the revenue requirement proposed by the OIEC vary significantly from that proposed by the OIEC.

**Removal of transmission expenses from base rates:** I raised concern in my rebuttal testimony regarding the removal of transmission expenses from the base rates with collection of these cost in the fuel adjustment as proposed by Mr. Farrar for the Public Utility Division. My concern is that if the transmission expenses currently allocated by a 12 month coincident peak method ( 12CP ) are moved to the fuel adjustment, these expenses will in effect be allocated based on energy used. The result would be a disproportional allocation to industrial customers. Also, I stated that it is premature to remove the transmission expenses from base rates until required by a future RTO tariff. I also recommended that even if a RTO transmission tariff is mandated, the 12CP method of allocating transmission cost should be maintained.

**John S. Thornton, Jr.**

**Direct Testimony**

Mr. Thornton testifies to Oklahoma Gas and Electric Company s (OG&E) appropriate return on equity (ROE) and overall rate of return (ROR) that should be allowed in rates.

Mr. Thornton recommends a 5.97 percent cost of debt compared to OG&E s proposed 6.03 percent cost of debt.

Mr. Thornton recommends using OGE Energy Corporation s consolidated capital structure of 52.49 percent debt and 47.41 percent equity as the capital structure in this case.

Mr. Thornton recommends a 9.0 percent ROE based on his capital asset pricing model and discounted cash flow model analyses of the cost of equity to the electric utility industry. He recommends a 7.41 percent overall rate of return.

A prepaid pension fund adjustment is discussed in the direct testimony of Mark E. Garrett. This adjustment affects Mr. Thornton s ROR. If the adjustment is accepted then Mr. Thornton s recommended ROR rises to 7.45 percent.

Mr. Thornton addresses Dr. Donald A. Murray s direct testimony regarding the return on equity, the cost of debt, the capital structure and the rate of return. Mr. Thornton expresses concern that Dr. Murray s recommended 11.75 percent ROE significantly exceeds Dr. Murray s



---

own cost of equity estimates. Mr. Thornton addresses analytical problems in Dr. Murray s cost of equity analyses and the inappropriateness of Dr. Murray s small-company size premium.

Mr. Thornton also briefly addresses the prefiled direct testimonies of Susan Abbott and Julie Cannell.

**Rebuttal Testimony**

Mr. Thornton s rebuttal testimony continues to recommend using OGE Energy Corporation s (OGE) consolidated capital structure to set the required rate of return (ROR) for Oklahoma Gas and Electric Company (OG&E). However, he discuses other alternatives based on the double leverage approach and the hypothetical capital structure approach. He also expresses concern that OG&E is not fulfilling Section II.10 of its holding company authorization order in Cause Number PUD 950000148 in which it agreed to maintain a balanced capital structure at the utility and ensure that the credit quality of OG&E is unaffected by the higher risks associated with the non-regulated businesses.

Mr. Thornton addresses the responsive testimonies of Edwin Farrar of the Oklahoma Corporation Commission Staff and John Dunn of the OG&E Shareholders Association.

Mr. Thornton finds that overall, Mr. Farrar s discounted cash flow (DCF) results are reasonable. Mr. Thornton expresses concerns about the fine points of Mr. Farrar s capital asset pricing analysis (CAPM) that is biased upward. Mr. Thornton finds that Mr. Farrar s 0.22 percent construction risk premium is not fully developed and that it is neither necessary nor appropriate to add to his DCF or CAPM estimates. Mr. Thornton does not recommend adopting Mr. Farrar s 0.20 percent flotation cost adjustment. That adjustment is not based on any OGE costs; rather, the adjustment was judgmentally determined. Mr. Thornton recommends an accounting-based approach to flotation costs that is fair to ratepayers and shareholders.

Mr. Thornton finds that Mr. Dunn s statistical risk calculation has mathematical and conceptual errors but that the measure is ultimately meaningless and should be ignored. Mr. Dunn s constant-growth DCF analysis is fraught with data problems and is biased upward due to an assumed 6.0 to 6.75 percent assumed dividend growth rate. Mr. Dunn s assumed growth rate range for his sample of electric utilities is higher than a forecasted dividend growth rate for the U.S. economy as a whole or a forecasted U.S. gross national product per share growth rate. Finally, Mr. Thornton addresses the inappropriateness of Mr. Dunn s adjustment for flotation costs and pre-offering pressure.

**Daniel E. Peaco**

Mr. Peaco s responsive testimony addresses the prudency of OG&E s acquisition of the McClain generating facility as well as the prudency of OG&E s procurement of gas transportation services for the McClain generating facility.

Mr. Peaco testifies that OG&E s acquisition of the McClain facility was not conducted prudently and, as a result, the OG&E costs to acquire the McClain facility exceed levels that are reasonable and prudent. He recommends that the Commission disallow $45 million of OG&E s



---

acquisition costs. OIEC witness Mark Garrett provides recommendations on implementation of this disallowance in rates.

Mr. Peaco s recommendations are based on the following findings:

1) OG&E s actions do not meet the need requirements of the Settlement Agreement. He testifies that OG&E relied, and continues to rely, on the capacity need assessment it conducted in the summer of 2002 as its primary justification for the need for the McClain facility despite the fact that, by its own analysis, its need had declined significantly before commitments were made to NRG. The need for the facility had clearly eroded at the time that OG&E executed the asset purchase agreement based on information that was known or knowable to OG&E at the time. Based on OG&E s own then-current information, a reassessment of the need for and economic value to ratepayers of the facility should have been done before entering the asset purchase agreement. In addition, OG&E s own need for capacity analysis continued to show much less need for capacity throughout OG&E s consideration of several amendments to the Asset Purchase Agreement, providing additional opportunities for OG&E to reassess the need for the acquisition.

2) OG&E s actions do not meet the requirements to consider alternatives to acquisition set forth in the Settlement Agreement. OG&E chose to ignore asset options that would be available after June 2004 and all short term and longer term purchased power alternatives. Mr. Peaco testifies that at the time the asset purchase agreement was executed, OG&E needed very limited amounts of additional capacity which could have been secured inexpensively from the surplus SPP market in the near term. OG&E also erroneously assumed it would purchase no capacity from existing QF contracts. Again, these opportunities extended through OG&E s process of amending the Asset Purchase Agreement.

3) OG&E s acquisition of McClain does not meet the requirements to consider the cost of the acquisition set forth in the Settlement Agreement. While OG&E s competitive negotiation approach produced a price for McClain that was favorable relative to the other assets it was considering, OG&E did not conduct an analysis of the least cost way to meet the needs of retail customers, particularly once its needs assessment indicated that much less than 400 MW was needed in the near term. In addition, once it became apparent that the costs of the acquisition would increase to meet the market power mitigation requirements, OG&E did not reassess the economics or examine options to terminate or renegotiate the agreement with NRG.

Mr. Peaco s recommendation for a $45 million disallowance is based on: 1) a cost estimate of a strategy of market purchases in the short-term, and then construction of a facility similar to McClain in the longer term, 2) disallowance based on the pro rata share of McClain that was needed to meet requirements per OG&E s own resource assessments, and 3) an assessment of comparable transactions, based on a cost per kw for two similar transactions in the first half of 2004.



---

In regards to OG&E s procurement of gas transportation service for the McClain facility, Mr. Peaco find that OG&E did not competitively bid for gas transportation services for McClain and, therefore, those costs are subject to prudency review in this proceeding under the terms of the Stipulation. He recommends that that the Commission reach the same finding in this proceeding as in its July 14, 2005 order (Cause No. PUD 200300226). He also asks the Commission to reaffirm its requirements of OG&E for competitive bidding for transportation services and the need for specific measures to assure fairness and transparency in OG&E s dealings with its affiliate, particularly in circumstances where there are few competitors or if OG&E does not utilize competitive bidding.

Mr. Peaco s rebuttal testimony focuses on the responsive testimony of Mr. George Mathai in which Mr. Mathai reaches the conclusion that the McClain acquisition was prudent. Mr. Peaco notes that Mr. Mathai appears to limit his review of the McClain acquisition to OG&E s new build alternative and the alternative asset acquisition options at the time OG&E decided to commit to the McClain acquisition. His testimony does not consider OG&E s need for the power or other alternatives that were available to OG&E at the time the transaction was closed. Mr. Mathai s testimony does not address whether the McClain capacity was needed or whether it was better than other options available to OG&E. Mr. Peaco notes that Staff was the only party that reached a conclusion of prudency regarding the McClain acquisition.

**ATTORNEY GENERAL**

**J. Bertram Solomon**

In my Responsive Testimony I present the results of my review and analysis of the rate of return and capital structure testimony of Dr. Donald A. Murry, the results of my cost of capital analyses and my recommendation for the appropriate capital structure and rate of return on common equity ( ROE ) for use in establishing the rates of Oklahoma Gas and Electric Company ( OG&E or the Company ) in this proceeding. I also comment briefly on the direct testimony of OG&E witnesses Julie M. Cannell and Susan D. Abbott.

In conducting my review and analyses, I applied the criteria set forth in *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ( *Bluefield* ), and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ( *Hope* ). In these landmark decisions, the Supreme Court established standards for measuring the cost of common equity capital. These standards are that the return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks and, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital. These standards also apply to the determination of an appropriate capital structure for use in calculating the allowable overall rate of return. Both involve the application of informed judgment and striking a proper balance between stockholders and ratepayers. In addition, I considered the guidance provided by the Oklahoma Supreme Court in *Turpen v. Oklahoma Corp. Comm n.*, 769 P.2d 1309 (Okla. 1988) ( *Turpen* ) and the Commission s Order No. 380443 (1994) in OG&E s last litigated rate case in Cause No. PUD 900000898, *et. al.*

67

---

In determining a fair rate of return on common equity which would meet the criteria of comparability of earnings and capital attraction, I have followed the general approach of reviewing the rate of return testimony of the Company s witness, Dr. Murry, and others, reviewing data responses related to the cost of capital and other available financial information, and conducting my own analyses to better reflect the requirements of investors.

Dr. Murry said his recommendation was derived from the application of the discounted cash flow ( DCF ) method and capital asset pricing model ( CAPM ) to OGE Energy and a group of six (6) electric utilities he believed to be comparable to OG&E. Dr. Murry says that the CAPM provides a valued comparison to the DCF measured cost of common stock and that the CAPM, which is less sensitive to prices and current conditions than the DCF method, is useful as a confirmation of the general level of the cost of capital. Murry direct at pp. 20 and 21. However, rather than using the CAPM results as a comparison to the DCF measured cost of common stock and confirmation of the general level of the cost of capital, Dr. Murry must have placed primary, if not sole, emphasis on the CAPM results because his recommended 11.75% is near the 11.6% average CAPM result but is 155 basis points, or 1.55%, higher than the 10.2% top end of his DCF results.

I disagree conceptually with Dr. Murry s significant reliance on the CAPM method as well as his specific applications of that method. While the risk/return principle underlying the risk premium theory and its CAPM offspring is valid from an academic perspective, these methods are fraught with problems of practical application as a reliable means of determining an allowable ROE. In practice, the risk premium based methods compound the complexity of estimating the underlying required rate of return of investors. Since the investors required rate of return on common equity is not directly observable, the process of estimating an appropriate risk premium (the calculation of which necessarily entails the use of some estimate of the investors required rate of return on common equity for some historical period for benchmarking purposes) is more complex and difficult than applying a direct method like the DCF method to determine the current market indicated cost of common equity of a company or proxy group of companies.

Also, because the determination of an appropriate risk premium necessarily relies on the use of specific periods of historical information, it is inherently backward-looking rather than forward-looking. The various methods used to determine risk premiums produce widely varying results and even the same method consistently applied over time demonstrates that risk premiums are very volatile over time. Given this significant volatility of historical risk premiums, in order to justify reliance on the results of a risk premium analysis, it is of critical importance that the economic and market conditions during the historical period selected for computation of the risk premium used, be shown to be comparable to the current conditions and those investors expect during the period the rates will be in effect. Without such demonstration, the risk premium used cannot be relied on as representative of the risk premium currently required by investors and the results are of no value for purposes of determining the current cost of common equity capital of the subject utility. Dr. Murry s direct testimony completely fails to address this issue at all much less provide convincing evidence that the market return and risk premium he uses were developed in a reasonable manner and using a time period where economic and market conditions were comparable to current conditions and those expected for the next few years when the rates established in this proceeding may be in effect. Furthermore,



---

fundamental and profound changes have taken place in the electric utility industry over the last decade or more and any historical risk premium calculated based on the prior industry environment cannot reasonably be expected to reflect current expectations of investors in electric utility stocks. I also discuss several specific problems with Dr. Murry s particular application of the CAPM methodology.

The DCF method is more direct and less complex than the CAPM or other risk premium methods. Regulatory commissions have generally recognized the appropriateness of using the DCF method as a means of satisfying the capital attraction and comparability of earnings tests because this method attempts to measure the market cost of equity capital or, in other words, investors required rate of return. Because the DCF approach uses marketplace data to establish the required rate of return, the rate of return developed through its appropriate application reflects returns from investments in instruments of comparable risk. Therefore, I have relied exclusively on the DCF method in developing my recommended ROE.

I first applied the DCF method to a proxy group of electric utilities that reasonably reflect the risk profile for OG&E. For my major selection criteria, I used well-known indicators of risk published by independent institutions the Value Line Safety Rank, Standard & Poor s ( S&P ) credit rating, and S&P common stock rank. These independent institutions consider a multitude of factors that indicate risk differences among companies and distill their analyses into simple indices of relative risk that are published for use by investors in more readily and easily determining the relative risks of the rated companies. Use of these published and widely followed risk ratings, I have assured that the selected companies are comparable in risk in the eyes of investors, not necessarily in my eyes or those of another witness. It is, after all, the cost of equity capital as determined by investors that is important here. In applying the DCF method, I also relied heavily on the projections of widely published investment analysts as the basis for the crucial dividend growth rate estimates. This, again, provides independent objectivity and forward-looking estimates that are likely to be more reflective of investor expectations than simple extrapolations of historical results.

The results of my proxy group DCF analyses are an average of 7.9% to 9.2% indicated required ROEs. Without the extreme lowest and highest results in each column, the range of individual company results is 7.4% to 9.8% with a midpoint of 8.6% and a median of 8.4%. As also shown on page 1 of that Exhibit, I applied the same methodology to OGE Energy, resulting in a range of 7.7% to 8.4%.

I also consistently applied the same DCF methodology to Dr. Murry s selected electric utility group using updated information. The results are shown on Exhibit ___ (JBS-4), page 1. The averages of the indicated low and high investor-required rates of return for Dr. Murry s group are 7.8% and 9.2% nearly the same as for my selected group. The range of calculated results for the individual companies without the extreme lowest and highest results is 7.4% to 9.5% with a midpoint of 8.4% and a median of 8.7%, again, very close to the results for my comparable group. Thus, correctly applying the DCF method to Dr. Murry s group using more current information confirms the reasonableness of the results for my comparable group.

Based upon my review and my own capital structure and cost of capital analyses, I concluded that the Company s request 11.75% ROE is excessive; and, that the ROE used in

69

setting the rates of OG&E in this proceeding should be 8.4% coupled with a capital structure comprised of 52.6% long-term debt and 47.4% common equity. The calculation of the weighted average cost is shown below:

Oklahoma Gas & Electric Company

Weighted Average Cost of Capital

| Type of Capital | Ratios | Cost Rates | Weighted Costs |
|---|---|---|---|
| Long Term Debt | 52.60% | 6.03% | 3.172% |
| Common Equity | 47.40% | 8.40% | 3.982% |
| | 100.00% | | 7.153% |

To conclude, I also reviewed the testimony of OG&E witnesses Cannell and Abbott and found their testimony to be of little practical use in determining the just and reasonable cost of common equity capital and overall rate of return for use in setting OG&E s rates in this proceeding.

**Scott Norwood**

In my responsive testimony I addressed the following major issues underlying OG&E s rate increase application:

1) OG&E s proposal to recover $51 million of post-test year Construction Work in Progress ( CWIP ) is unreasonable and fails to account for other known and measurable changes to its rate base. I recommend that the Company s rate base be updated to reflect actual plant in service, accumulated depreciation and accumulated deferred income tax balances as of June 30, 2005. This recommendation reduces OG&E s Oklahoma jurisdictional rate base by approximately $83.5 million.

2) OG&E s proposed Cash Working Capital request of $38.6 million is based on a flawed lead/lag study which includes a number of large non-cash items. Although a negative cash working capital could be justified, I recommend that OG&E s cash working capital be set at $0 (zero) for this case.

3) OG&E is proposing that its $25.86 million McClain Regulatory Asset be included in rate base. In light of the short 3-year amortization proposed for this asset, I recommend that this item be removed from rate base and that OG&E s return on this asset be based on the Company s short term cost of debt as of June 2005, which is 3.18%.

4) OG&E is proposing that it be allowed to increase its fuel oil inventory by approximately 120% from the test year level. This proposal is excessive and unjustified. I recommend that OG&E s fuel oil inventory be based on the 13-month average level for the period ending June 30, 2005, which reduces the Company s proposal by $3.93 million.

5) OG&E has requested $13.5 million of incentive compensation cost in its new rates. I recommend that OG&E s proposed request for incentive compensation costs be

reduced by $7.7 million to remove the portion of these incentive payments that are based on performance targets that primarily benefit the corporation and its shareholders.

6) OG&E is proposing to recover $57 million (more than 82%) of OGE Corporation s administrative and general (A&G) costs. I recommend that OG&E s proposed allocated share of corporate A&G costs be reduced by $7.5 million, based on the allocation method recommended by OCC Staff witness George Mathai in OCC Cause No. 200400610.

7) I recommend that OG&E s proposed McClain Regulatory Asset be adjusted to reflect the December 31, 2003 acquisition date of the facility advocated by the Company in OCC Cause No. 200400004, to remove costs which have already been recovered through the Company s fuel cost adjustment rider, and to reflect the appropriate allocation of such costs to the Oklahoma jurisdiction. My recommendations reduce OG&E s proposed annual amortization for the McClain Regulatory Asset by approximately $5.5 million.

8) I recommend that OG&E s proposed adjustment for minor storm costs be reduced by $2.3 million to prevent the double recovery of OG&E employee labor costs that are also recovered in the Company s test year payroll adjustment. In addition, I recommend that the OCC reject OG&E s Major Storm Expense Rider.

9) Consistent with my recommended adjustments to update OG&E s proposed rate base, I recommend that OG&E s requested depreciation expense be reduced by $1.0 million to reflect actual amounts as of June 30, 2003.

10) I recommend that OG&E s proposed recovery of $400,000 of lobbying expense be disallowed because such costs primarily benefit OG&E and its shareholders.

11) I recommend that OG&E s authorized return on equity in this case be reduced by 50 basis points in order to penalize the Company for its failure to evaluate or otherwise document purchased power alternatives to the acquisition of the McClain facility. Based on the AG s recommended rate base and cost of capital, this penalty would be approximately $4.1 million.

I also filed rebuttal testimony in which I addressed OIEC witness Mr. Gregory s fuel cost allocation proposal. OIEC proposes a radical change in the way that fuel costs historically have been allocated among customer classes in Oklahoma and other jurisdictions. He seeks to assign fuel costs based on the Average and Excess Demand ( AED ) production plant allocation method, rather than on a system average fuel cost basis. The result of his AED fuel cost allocation proposal would be a devastating increase in fuel charges to small residential and commercial customers and a concurrent dramatic decrease in fuel charges borne by high load factor industrial customers. I recommended that the Commission reject

Mr. Gregory s radical proposal for allocating fuel expenses based on the AED production plant allocation method.

71

---

**PUBLIC UTILITY DIVISION**

**Helen Patel**

**Payroll & Related Taxes Unfilled positions to be filled by June 30, 2005** Staff proposes the reversal of OG&E s Adjustment #H-27 for a resulting decrease to Payroll Related expenses by $3,423,005 for total company. Of this amount, $3,195,850 is related to payroll expenses and $227,155 is related payroll taxes. Staff recommends this adjustment be reversed because the additional level of employees requested by OG&E is already included in the payroll adjustment as sponsored by Staff witness Malini Gandhi. Staff is proposing that actual increase in the payroll levels at June 30, 2005 be included in rates rather than the estimated increase proposed by Company.

Staff would also like to inform the Commission that the level of expense or investment arrived by Staff is based on the review of evidence and facts provided by the company and individual research by the staff. The adjustments made are based on sound ratemaking principles, which is representative of all stakeholders in the current cause.

**Other Issue Areas**

The following areas were reviewed by Staff, but no adjustments were proposed: OCC Assessment Fees, Regulatory/Rate Case Expense, Customer Deposits and Interest on Customer Deposits.

Staff had addressed several other issues during the audit. However, we are not proposing any specific adjustments at this time on any of those issues.

**Crecetta L. Herbison**

**Advertising Expense:** Staff proposes to remove a total of $718,835 from the total Company Pro Forma level of advertising. $628,695 is advertising campaigns and associated costs included within the O&M expense in the test year period that reflect charges to the Demonstrating and Selling Expense accounts that is promotional in nature. $80,713 is the Supervision of Sales Expenses. And $9,427 is Miscellaneous Sales Expense. This adjustment is necessary to eliminate certain test year advertising expenses that Staff believes should not be recoverable for ratemaking purposes. These expenses promote one form of energy over another and/or provide the Company with goodwill to improve the Company s image. The disallowance of advertising for Sales Activity is consistent with the previous treatment by the Commission. Staff addressed several issues during the audit. However, we are not proposing any specific adjustments at this time on any of those issues.

**Edwin C. Farrar, CPA**

Mr. Edwin C. Farrar, CPA, is manager in the Economic Analysis and Research Group of the Public Utility Division. I have supervised rate cases and the annual fuel adjustment clause audits of public utilities for several years. In Oklahoma Gas and Electric Company s ( OG&E ) current rate case filing, my Pre-Filed Responsive Testimony illustrates Staff s proposed

72

recommendation regarding the following issues: 1) the Return on Equity ( ROE ); 2) Long-Term Debt Cost; 3) Preferred Stock Cost; 4) Capital Structure; 5) Overall Rate of Return, and 6) Rate Design. In arriving at Staff s proposed recommendation regarding the Cost of Common Equity, the Discounted Cash Flow ( DCF ), and Capital Asset Pricing Model ( CAPM ) methodologies were used. Staff also considered the risk associated with OG&E s construction program. The following table summarizes Staff s analyses of the Return on Equity:

TABLE ECF-1:

Results of Staff s Analyses of OG&E s Return on Equity

| | |
|---|---|
| DCF Comparative Companies *Value Line* | 8.24% |
| DCF Comparative Companies *Yahoo* Finance | 8.33% |
| DCF Comparative Companies *Zacks* | 8.88% |
| Average Discounted Cash Flow ( DCF ) | 8.48% |
| CAPM Comparative Companies | 10.17% |
| Average Comparative Return on Equity | 9.33% |

| | |
|---|---|
| Flotation Costs | 0.20% |
| Additional Risk Adjustment | 0.22% |
| Staff s Recommended OG&E Return on Equity | 9.75% |

Based upon the results of the DCF, and CAPM models, Staff s recommended fair Return on Equity for OG&E is 9.75%. Staff s analyses suggest a reasonable range of 8.44% to 10.37% for the ROE. The 9.75% ROE is the average of the DCF estimates and the CAPM estimate, adjusted for flotation costs and the impact of plant additions related to Commission reliability rules. Staff s ROE recommendation does not include risk compensation from the flat bill option or the various incentives available or proposed for OG&E.

The criteria used to determine a fair and reasonable Rate of Return included the Economic Guidelines and Standards known as the Comparable Earnings and Capital Attraction Standards established in the *Bluefield* (1923) and *Hope* (1944) decisions. The public utility has the opportunity to earn this return on the Commission allowed rate base. Current economic conditions and projected industry information as well as the Return on Investments of Comparable Risk were considered.

The DCF model is derived from present value theory and rests on the assumption that the value of a financial asset is determined by its ability to generate future earnings. The results of the constant growth DCF analyses are shown on Schedules ECF-1, ECF-2, and ECF-3 contained within Staff s Rate of Return Exhibit. The ROE range in the three DCF schedules is from 8.33% to 8.88%.

The theory supporting the Capital Asset Pricing Model ( CAPM ) method of estimating Capital Costs rests on the premise that investors require a Rate of Return commensurate with the

73

---

risk of the investment. The interest rate on a current 20-year U.S. Treasury Bond is used in this calculation. The results of the CAPM analysis indicate a ROE estimate of 10.17% for the comparable group.[14]

Staff recommends the Capital Structure at June 30, 2005 of OG&E, adjusted to remove the accumulated comprehensive loss adjustment to equity that appears on OG&E s balance sheet. Staff s resulting OG&E Rate of Return and its components are illustrated below in Table ECF-2:

<u>TABLE ECF-2</u>:

Staff s Resulting Recommended Rate of Return OG&E

| *Description* | *Ratio* | *Rate* | *Rate of Return* |
|---|---|---|---|
| Long-term Debt | 42.971% | 5.93% | 2.548% |
| Common Equity | 57.029% | 9.75% | 5.560% |
| TOTAL | 100.00% | | 8.109% |

My Pre-Filed Rebuttal Testimony addresses issues raised by Glen E. Gregory and John C. Dunn regarding the following issues: 1) Time of Use Rate Design; 2) Production Demand Allocation; 3) Gradualism; and 4) Stockholder Risk. Regarding Mr. Gregory s testimony Staff agrees with much of his rate design discussion. OG&E s proposed rate design charges higher rates for high summer usage and reduced rates for high winter usage. The use of a high tail block rate is not effective in controlling demand or summer consumption and should be reconsidered. It would be more effective to have a time of use allocation of fuel costs to properly assign costs to the cost causer. This would charge customers more for using power during high cost time periods and less during low cost periods. If a high tail block summer rate design is retained customers should be educated about the higher rates for high consumption. Staff also acknowledges that the increase in the LPL class maximum demand allocation in this Cause is not supported by the changes in usage by this class. Staff recommends further that Gradualism is also a rate design principle that should be followed in this cause. Care should be taken not to allocate too much of an increase on any customer class in this proceeding, or any rate increase if all other classes receive a rate reduction. Regarding Mr. Dunn s testimony Staff disagrees with his Risk Adjustment. Instead OG&E should utilize a rate design that does not rely on high tail block rates to achieve the Company s authorized return. This is a high-risk rate design can result in a substantial windfall for stockholders with warmer than normal summer weather and it can result in a low return when summer weather is cooler than normal. Ratepayers should not be penalized for a high-risk rate design that provides limited benefit to them. Staff recommends that Mr. Dunn s risk adjustment be rejected.

---

[14]*Reference* Schedule ECF-4.

74

---

**Reema Malhotra**

**Dues, Donations, Contributions and Membership Expenses**: Staff proposes the removal of $81,706 from the total operations expenses included in OG&E s cost of service related to dues, donations, contributions, and membership expenses. Staff does not believe that these expenses are necessary to the provision of electric service. Additionally, these expenses would require ratepayers to involuntarily contribute to various organizations and causes, both charitable and non-charitable in nature.

**Community and Social Activities**: Staff proposes the removal of $251,718 associated with the employees community and social activities that are included in the cost of service. OG&E employees are compensated through salary and benefits. OG&E included certain community and social activities in this case, which are an indirect additional benefit to OG&E employees. In Staff s opinion, this expense is merely incidental to the employment relationship and is not essential to providing electric utility service to Oklahoma ratepayers. As such, Oklahoma ratepayers should not be required to pay for these other incidental expenses that do not further the provisioning of electric service.

**Outside Services/Legal Expenses**: Staff proposes the removal $902,861 of outside services associated with litigation that should not be paid for by Oklahoma ratepayers. It represents an integrated amount made up of legal fees associated with Arkansas litigation, Non-utility operations, and other shared costs. Staff is proposing to share the amount spent by Company for Professional Service, which partly benefits the ratepayers.

**Legislative Advocacy/Lobbying**: Staff proposes the removal of $465,432 of legislative advocacy/lobbying expenses. These lobbying and legislative expenses are mainly incurred to meet the Corporate and Shareholder objectives. Often many of the legislations are in conflicts with the ratepayer interests. Since ratepayers do not have any input in the decision-making process of which issues the utility will support for purposes of lobby efforts, such costs should not be included in the cost of service. If Oklahoma ratepayers were required to pay for this expense, the Oklahoma Corporation Commission would be forcing Oklahoma ratepayers to involuntarily support certain legislative issues that are not in the best interests of the ratepayers. Utility Commissions across the country have generally excluded lobbying expenses for ratemaking purposes, including this Commission.

**Research and Development**: Staff proposes the removal of $423,869 of research and development expenses. The projects represented in these expenses are not complete, and the cost savings, if any, related to this function cannot therefore, be evaluated at this time. Staff proposes that any related-costs should be deferred and expensed when benefits are actually received from those efforts. Recognizing the research and development expenses now without recognizing the associated revenues (or reduction of expense levels) are not consistent with the matching principle of accounting and ratemaking process. Staff considers estimated or future revenues are beyond the known and measurable levels of the test-year, and are therefore not quantifiable. Also, the expenditures incurred for research will be recovered through the future revenues of the developed product sales. Therefore today s customers should not be forced to pay for these costs.

**Materials and Supplies**: Staff proposes pro forma adjustment of $1,347,435 associated with materials and supplies expense. This amount was calculated based on the information provided by OG&E during Staff s audit. Staff used the 13-month average ending on June 30, 2005 as the pro forma level, representing activity on an ongoing basis. The adjustment is the difference between test- year ending balance and updated 13-month average ending June 30, 2005.

**Prepayments Pre-paid Pension Benefit Obligation**: Staff proposes the removal of $67,156,464 year end balance of pre-paid pension benefits included by OG&E in the rate base. This item is removed from the rate base and given the Alternative Financing Methodology treatment for the 13-month average level of $52,893,979 in the ratemaking process. This will further be addressed in the Pre-Filed Responsive Testimony of Staff Witness Mr. George Mathai.

**Prepayments Other**: Staff proposes pro forma adjustment of $543,361 associated with Prepayments- other. Staff agreed with the methodology used by OG&E i.e. the 13-month average ending December 2004. This adjustment was due to Staff excluding the prepayments associated with EEI Dues and Economic Development membership fees. These items are normal expenses of doing business and should not be in the rate base and earn a rate of return while at the same time recovering the amount in the cost of service.

Staff had addressed several issues during the audit. However, we are not proposing any specific adjustments at this time on any of those issues.

**Malini Gandhi**

**Plant-In-Service Utility (B-1)**: Staff proposes the removal of $35,742,734 from OG&E plant-in-service to reflect the actual updated plant balance provided by OG&E as of June 30, 2005. This adjustment is related to the projects included in plant as of June 30, 2005. OG&E requested the inclusion of $138,258,631 in Construction Work In Progress ( CWIP ) in the rate base of its original filing. Staff reviewed the updated plant-in-service balance as of June 30, 2005 and recommended the allowance of $102,515,897 as completed and transferred to plant-in-service projects. Therefore, Staff s resulting recommendation is the rate base reduction of plant-in-service utility in the total amount of $35,742,734.

**Plant-In-Service Holding Company (B-2)**: Staff recommends an increase to the plant balance by $2,865,225 to reflect the known and measurable changes as of June 30, 2005 as they relate to plant-in-service for OG&E s holding company, OGE Energy Corporation. OG&E originally requested $54,996,208 to be included as its holding company plant balance included in the rate base. Staff removed $10,824,978 related to the non-utility related plant from OG&E s updated balance of $68,686,411 as of June 30, 2005, for a resulting recommended allowance of $57,861,433 in plant related to OGE Energy Corporation. Therefore, Staff s resulting recommendation is the rate base increase of $2,865,225.

**Construction Work In Progress (CWIP)(B-13):** Based on the Technically Completed ( TECO ) Projects analysis as of June 30, 2005, Staff recommends an increase in Plant In Service balance for the amount of $31,902,958 related to CWIP. The data provided by OG&E as of June 30, 2005, listed total CWIP for $88,543,819, and out of that the projects for $46,594,068 were listed as Technically Completed. According to OG&E these projects were used and

76

useful and providing service to the ratepayers on or before June 30, 2005. However, Staff estimated 31.53% of cost associated with Technically Completed Plant as retirement, replacement and removal cost, and should be removed.

**Payroll Expense (H-6)**: Staff proposes a $1,251,968 reduction to the OG&E pro forma payroll expense. Staff annualized the payroll level based on the June 30, 2005 wage and employee level for OG&E, and its holding company, OGE Energy Corporation. Staff s proposed adjustment to payroll expense in this area is comprised of the following components:

1. Staff annualized the June 30, 2005 full-time employee payroll amounts provided by the Company.

2. Staff applied a corporate allocation factor of 69.95% to OG&E s holding company s payroll instead of OG&E s allocation factor of 75.20%. Staff s proposal resulted in a $1,832,999 reduction of payroll expenses.

3. Staff did not propose any changes to the capitalization factor of 76.67% used by OG&E for calculating OG&E s payroll. Staff s proposal resulted in a $581,031 increase to OG&E s payroll expense due to the updated payroll up to June 30, 2005.

4. Staff modified the corporate allocation factor utilized by OG&E and increased the payroll amount by annualizing the payroll as of June 30, 2005 for a resulting $1,251,968 decrease to total OG&E requested payroll.

**Payroll Taxes (H-8)**: Staff calculated its payroll tax adjustment to reflect any changes in OG&E s payroll, and incentive pay adjustments calculated in Staff s Pre-Filed Testimony. Staff used an effective rate of 7.11%, which is the same as that used by OG&E, to calculate the payroll tax adjustment. Staff s proposal resulted in a $490,363 reduction to payroll taxes.

**Employee Incentive Compensation (H-10)**: OG&E s total requested incentive pay in this current cause was $12,236,204, as paid out for the test-year, including $5,175,634 as executive compensation. Again, the breakdown between the holding company, OGE Energy Corporation, and OG&E, the subsidiary in this cause totals $4,934,640 and $7,301,564, respectively.

Staff is proposing a sharing mechanism consistent with the various incentive programs described and payments made by the company to each program. Staff submits that 75% or more of the holding company s executive compensation is targeted to measure the operating success of the Company from a financial perspective, and as a result, would primarily benefit shareholders. Therefore, only 25% or less of the executive compensation should be borne by the Oklahoma ratepayers.

At the same time, some of the OG&E s incentive compensation programs not only measure its financial success, but it also measures customer reliability and safety, along with savings to customers. Therefore, it should be shared between customers and shareholders on an equal basis. Based on Staff s findings that 25% of the holding company, and 50% of OG&E s employee compensation should be borne by Oklahoma ratepayers, along with application of Staff s recommended Allocation/Capitalization factors, Staff proposes an employee incentive

77

pay calculation of $3,662,000. Staff s proposal results in a $5,646,959 reduction in OG&E s employee incentive compensation.

**Gain On Sale of Assets (H-12)**: During the test year, OG&E realized profit on the retirement of certain fixed assets that were included in the rate base in the amount of $3,481,816. Staff submits that this gain on sale of assets should be passed on to the ratepayers since related costs originally passed along to customers in the rate base. Staff calculated three-year average for the profit on retirement or disposition of the property included in the rate base. Staff s review of these gains showed unusually high amount of gains in the test year as compared to past two years. In order to normalize these gains staff proposed the three-year average. This adjustment resulted in a $1,338,941 reduction to other Operating & Maintenance expenses.

**Other Issues:** Staff is addressing the following areas, which were reviewed by Staff, but no adjustments were proposed:

Sarbanes-Oxley Compliance

Vegetation Management

Staff had reviewed and addressed several other issues during the audit. However, we are not proposing any adjustments on any of those issues.

**Jason Thenmadathil**

**Regulatory Assets**: Staff proposes to remove the entire balance included in the Rate Base for the McClain Regulatory Asset and allow it an alternative ratemaking treatment. The unamortized balance of the McClain Regulatory Asset, which has been updated by Staff, will be calculated as a 4-year average balance and given an alternative financing option.

Also, Staff recommends that OCC Assessment fees which was included as a Regulatory Asset by the Company be removed from the Rate Base. OCC Assessment Fees are a cost that is being expensed in the base rates. The OCC Assessment Fees that are included in the Regulatory Asset are an accrual of OCC Assessment Fees that are later expensed. OCC Assessment Fees are costs that should be expensed like any other normal business expense.

For all other Regulatory Assets, Staff proposes to update the balances for six months post test year. The total adjustment is a reduction of $28,483,854 to the Rate Base.

**Regulatory Liabilities:** Staff proposes to update the balances for all regulatory liabilities as of the six months following the test year. The total adjustment is an increase of $1,394,502 to the Rate Base.

**McClain Gas Transportation Expenses**: Staff proposes to reduce OG&E s Pro Forma adjustment related to McClain Gas Transportation expenses to correct an overstatement in the Company s McClain Transportation Adjustment. The total adjustment is a reduction of $494,703 to the Income Statement.



---

**McClain O&M Expenses**: Staff proposes to increase the level of McClain O&M Expenses based on known and measurable data as of June 30, 2005. The total adjustment is an increase of $324,154 to the Income Statement.

**McClain Regulatory Asset Amortization**: Staff recommends reducing expenses associated with the amortization of the McClain Regulatory Asset. This is based on Staff s update to the regulatory asset and Staff s recommended depreciation expense level. Staff recommends increasing the depreciation rate for McClain Plant Prime Movers from 30 years to 40 years. This depreciation expense level increases the useful life of Prime Movers assets in order to take into consideration the Long Term Service Agreement. Additionally, Staff has proposed a depreciation rate that is even less than the annual rate in the test year for the Prime Movers Account (account 343).

Staff also proposes a 4-year amortization rate. In addition to the regular expenditures for the McClain Plant, customers will have to pay for out-of-period McClain Plant expenditures. Since both of these expenditures will have a cumulative impact on customers, the overall impact should be considered, so Staff chose a 4-year amortization rate to consider this overall impact. The total adjustment is a decrease of $2,713,032 to the Income Statement.

**Other Issue Areas**

**Bad Debt Expense:** OG&E s adjustment H-19 was an adjustment to bring Bad Debt Expense to its actual experience for the test year. Based on available information, Staff makes no adjustment to Bad Debt Expense at this time.

Staff had addressed several other issues during the audit. However, we are not proposing any specific adjustments at this time on any of those issues.

**Marvin D. Vaughn**

On behalf of the Oklahoma Corporation Commission ( OCC ), the following issues are the focus of the testimony of Marvin D. Vaughn:

**Ad Valorem Taxes**: OG&E proposes Ad Valorem taxes be included as an operating expense based on an allocated percentage of the total of OG&E s property tax obligation as it pertains to the Oklahoma jurisdiction. This amount includes the total amount of Ad Valorem Tax assessed by the Oklahoma Tax Commission and that of the Arkansas Public Service Commission Tax Division, which includes the actual impact of the acquired McClain plant. The total amount was then allocated to the Oklahoma jurisdiction based on OG&E s allocation factor. Staff found that the allocated level of Ad Valorem taxes included in the Company s filing is reasonable and therefore proposes no adjustment at this time.

**Insurance Expense**: OG&E proposes to decrease its operating income by $476,651, to reflect the decrease in insurance premiums it experienced in the test year and the 6-months post-test year. Staff analyzed the premiums for accuracy and found that the actions of OG&E were appropriate and therefore Staff proposes no adjustment to OG&E s asserted decrease in operating income at this time.



---

**Fuel Expense**: OG&E s fuel expense consists of totals related to Coal, Natural Gas, and Fuel Oil. In the test year, OG&E did not make any fuel oil purchases, so Staff s analysis was confined to OG&E s coal purchases, and associated coal transportation costs; and, its natural gas purchases, and associated gas transportation costs. Staff also reviewed OG&E s purchase contracts with its coal and natural gas suppliers, while tying those contracts to invoices. Staff s analysis determined no differences and therefore proposes no adjustment to fuel expense as proposed by OG&E in its filing at this time. Staff will be conducting additional review of the fuel issues in its regular Annual Fuel Audits.

**Purchased Power**: Staff reviewed OG&E s cogeneration contracts to verify the expenses associated with those contracts. Staff s review determined no differences in the cogeneration contracts, and therefore Staff recommends that the levels proposed by OG&E regarding purchase power contracts be accepted in this cause at this time. However, Staff plans to conduct additional review during the Annual Fuel Audit of the Company.

**Line-Loss**: Staff reviewed the Line-Loss report prepared by OG&E Consultants, Stone & Webster Management Consultants, Inc. and determined that there were no differences. This report was completed on October 14, 2003 and provided to the Commission as required by the Final Order issued in Cause Number PUD 200100455 ( PUD 455 ). Therefore, Staff proposes no adjustment to the line-loss levels proposed by OG&E in this cause at this time.

**Cogeneration Credit Rider**: In the Final Order of Cause Number PUD 1055, the Commission provided for the inclusion in its base rates of OG&E s costs associated with its two cogeneration contracts, AES Shady Point, Inc. ( AES ) and PowerSmith Cogeneration Project, LP ( PowerSmith ). The Commission set the cost level of those contracts at $178.6 million, with no credit rider mechanism. In OG&E s last rate case, PUD 200100455, a credit rider mechanism was then established. Whenever OG&E s payment obligation on those contracts dropped below the $178.6 million level, a mechanism was created that last rate case to return the difference of the base rate level received by OG&E from ratepayers and the actual obligations to the two cogeneration facilities. This mechanism returned the noted difference for the years 2003 and 2004 to the ratepayers. Staff has been able to verify the effect of the credit mechanism through an analysis of customers bills. In addition, in 2004, OG&E presented another credit mechanism in Cause Number PUD 200400391 ( PUD 391 ), which would return the same described difference for the years 2005, 2006 and 2007 to the ratepayers. Although an analysis of the noted credit mechanism for the test year has been completed for this cause, Staff will not be able to verify the results for any subsequent years until the end of 2005 and the end of each year following. Therefore, Staff does not propose any adjustment to the Credit Rider as proposed by OG&E in this cause at this time.

**Fuel Cost Removal & True-Up**: Staff reviewed the fuel cost proposed for removal by OG&E in its filing along with the trued-up amount based on 14 mills. OG&E told Staff that the trued-up amount was based on an amount of $46.8 million for gas transportation and storage cost. In Cause Number PUD 200300226, the Commission authorized a level of $41.9 million for transportation and storage services. The difference was recognized by OG&E as an annual adjustment of $4.9 million.

80

---

**Michael Read, CPA**

**Fuel Inventory:** Staff recommends a reduction of $7,417,846, to OG&E s filed position regarding their coal inventory level to approximate its historical levels. Specifically, Staff recommends a coal inventory level of 1,980,000 tons or $30,545,766, an average price of $15.43/Ton. This would be a 60-day inventory supply. Staff further recommends a reduction of $2,970,293 to OG&E s filed position regarding their fuel oil inventory level. The recommended fuel oil inventory is to adopt the 13-month average inventory balance of 10,244,778 gallons or $5,552,055 at an average price of $0.543/gallon. Staff accepts the Company s recommendation for current gas inventory of 2,200,000 MMBtu s or a total of $7,870,576 at an average price of $3.578 per MMBtu.

**Maintenance & Repair Expense:** Staff recommends a reduction to OG&E s filed position on maintenance expense in order to normalize boiler plant and electric plant expenditures at a three-year average expenditure level, thereby smoothing a recent spike in maintenance expenditures. This will entail reducing OG&E s expense balance for boiler plant by $2,475,932 and reducing the expense balance for electric plant by $2,891,902. Staff elected to go with a three year-average so as to more nearly capture the recent price run-ups in the price of steel and other items required to maintain an electric generating plant. This treatment more accurately reflects the current reality of the maintenance of an electric generating plant.

**Natural Gas Transportation, Enogex and Affiliate Transactions:** Staff had addressed several issues during the audit. However, we are not proposing any specific adjustments at this time on any of those issues.

**Robert C. Thompson, CPA**

On behalf of the Oklahoma Corporation Commission ( OCC ), the following issues are focused on in the testimony of Robert C. Thompson, CPA:

**Cash Working Capital:** Commission Staff recommends an adjustment to the cash working capital, which includes all of Staff s proposed changes to those accounts included within the cash working capital calculation. Staff is also 1) proposing an adjustment to the cash working capital to exclude non-cash items such as depreciation, investment tax credit and common equity, and 2) removing cash working capital from rate base while providing alternative financing recovery for OG&E s costs. Staff s adjustment will decrease cash working capital included in rate base by $38,607,809, and include a positive $34,667,976 as an asset with alternative ratemaking financing for OG&E s cost.

**Depreciation:** Commission Staff recommends accepting OG&E s Depreciation Study results and making an adjustment to depreciation expense, which includes all of Staff s proposed adjustments to plant-in-service, and updating depreciation expense to June 30, 2005. Staff s adjustment will decrease depreciation expense by ($662,550)

**Accumulated Depreciation:** Commission Staff recommends an adjustment to Accumulated Depreciation, which includes all Staff s proposed adjustments to Plant-In-Service. Staff s adjustment for Accumulated Depreciation will decrease Accumulated Depreciation by

($38,071,196). This adjustment updates accumulated depreciation balance to the six-month post test-year balance.

**Accumulated Deferred Income Taxes:** Commission Staff recommends an adjustment to accumulated deferred income taxes ( ADIT ) to increase deferred income taxes and reduce rate base by ($18,951,932). This adjustment updates accumulated deferred income tax balance to the six-month post test-year balance.

**Interest Synchronization:** Commission Staff recommends an adjustment to the interest expense within the income tax calculation to reflect changes to the rate of return and rate base. Interest synchronization is a method that provides an interest expense deduction for regulatory income tax purposes equal to the ratepayer s contribution to OG&E for interest expense coverage. Staff s Adjustment for interest synchronization will increase the net income before income tax by $9,166,098.

**Current Tax Expense:** Commission Staff recommends an adjustment to current income taxes to reflect Staff s adjustments to the operating income statement, resulting in a net decrease to OG&E s operating income of $14,083,403.

At this time I don t have anything to add to my testimony summary, but I reserve the right to add to this summary as needed and/or modify my testimony as more information is submitted by the parties.

Staff addressed several issues during the audit. However, we are not proposing any specific adjustments at this time on any of those issues.

**George Mathai**

The following issues are the focus of my testimony:

I am sponsoring the overall Staff Accounting Exhibit, which explains Staff s recommended Revenue Requirement for OG&E. I am also specifically testifying to related issues in the area of 1) Pension Expense, 2) Post Retirement Benefits, 3) Active Medical Benefits, 4) Retirement Savings Plan, 5) Corporate Allocation, 6) Prudence of McClain Plant Purchase and related Fuel Transportation costs, 7) the Storm Damage Rider (SDR)/Storm Expense Level. Additionally, my Pre-filed Responsive Testimony addresses Staff s recommendations related to the ratemaking treatment of certain Working Capital items such as 8) Prepaid Pension Accrual, and 9) Regulatory Assets, 10) Cash Working Capital while other Staff members will address specific aspects of each of the issues set forth in the Accounting Exhibit.

Section A, Schedule-1 of Staff's Accounting Exhibit sets forth Staff s computation of OG&E s Revenue Requirement. In this cause, Staff proposes a jurisdictional Revenue Deficiency for OG&E of $13,126,843 as shown on Line 7 of Schedule-1. This finding of Revenue Deficiency for OG&E incorporates Staff's recommended adjusted jurisdictional rate base of $1,701,820,419 adjusted jurisdictional operating income of $129,873,548 and rate of return of 8.109%.

82

---

**Pension Expense:** OG&E requested $25,196,896 as a pro forma expense level for pension expense. Upon review of OG&E s Pension Actuarial documents, Staff found that the assumptions and calculations do not match. Therefore Staff proposes minor changes to the amount calculated by OG&E to conform to the current actuarial assumptions. First, Staff applied OG&E s projected discount rate of 5.75 percent to OG&E s Projected Benefit Obligation and recalculated the interest cost. Secondly, Staff recalculated the expected Rate of Return on Assets at the 8.75 percent, which was used during the current year. Thirdly, Staff recalculated the Net Loss Recognition, using the same methodology as the Company. Fourth, Staff proposes Corporate Allocation Ratio of 69.95 percent, instead of the Company s 75.2%. The composite effect of these Staff recalculations made a reduction of $1,876,257 in OG&E s pro forma pension expense level. Staff proposes these minor changes to the amount calculated by OG&E to conform to the current correct actuarial assumptions.

**Post-Retirement Benefits Other than Pension**: Staff made similar adjustments as described in the pension expense, except that Staff did not recalculate the Net Loss Recognition amount in this adjustment. The recalculation resulted in an increase of $68,082 from OG&E s pro forma level request. Staff proposes these minor changes to the amount calculated by OG&E to conform to the current correct actuarial assumptions.

**Active Medical Benefits Expense**: Staff supports OG&E s request with a minor modification. Staff recalculated the request by applying the Corporate Allocation Ratio of 69.95 percent against Company s 75.2%. The effect of these Staff recalculation made a reduction of $113,317 in OG&E s pro forma Active Medical Benefits Expense level.

**Retirement Savings Plan**: Staff s position is that this is an optional benefit plan by OG&E for certain participating employees. The portion disallowed is for the matching of those employees who were hired prior to 2000, and who were receiving very competitive retirement compensation. Staff did allow $779,188 that OG&E matched for those participating employees who were hired after 2000, and under its new retirement program, which provides reduced benefits. If OG&E chooses to continue with the plan, its costs should be born by OG&E s stockholders instead of the ratepayers. In order to maintain fair, just and reasonable rates, Staff proposes the removal of $3,050,583 paid as additional compensation to selective group of employees, from OG&E s cost of service for ratemaking purposes.

**Corporate Allocation Factor Methodology**: Staff proposed three factors to compute and to allocate residual corporate overhead and administrative and general costs which cannot be directly assigned or allocated to a business unit, in this case as follows: (1) Gross Plant (2) Net Operating Revenues, and (3) Earnings before Interest, Taxes, Depreciation, and Amortization (EBITDA). The Company proposed three factors are, Gross Plant, Net Operating Revenues and Payroll. Staff proposes the substitution of ( EBITDA ) for Payroll, as one of the three components in Staff s calculation of OG&E s corporate allocation factor in this filing. Use of payroll allows the Parent Company to allocate more of the unassigned costs, from the non-regulated utility to regulated utility. One of the recognized advantages of using EBITDA as proposed by Staff is that EBITDA is free from the repetitious payroll impact as seen when payroll is used for this calculation with gross plant and net operating revenues as the other two factors of the calculation. Additionally, financial managers and analysts more commonly use a

83

firm s current cash flow to measure corporate success, and corporate shareholder equity value. Incidentally, this is a major point that the Company is trying to impress upon the Commission in determining its overall Revenue Requirement. For these reasons and more explained in my detailed testimony, Staff s methodology is more appropriate in setting fair, just and reasonable rates for OG&E. Staff s methodology resulted in a corporate allocation factor of 69.95% instead of Company s proposed factor of 75.2%. This results in a $2,279,147 reduction of OG&E s requested revenue requirement.

**Storm Damage Rider (SDR)/Storm Expense Level:** Staff is not in support of establishing a Rider for Storm Damage. Staff recommends that this Commission deny OG&E s request for a Storm Rider in this cause, as this Rider is an unnecessary Piecemeal ratemaking, and it is not related to a unique or extraordinary situation that requires a Rider mechanism for appropriate recovery. Riders in general add unnecessary *regulatory clogging* by requiring the exhaustive monitoring within a very short time period, thereby utilizing the already-limited resources of the regulatory agency. Riders are also used by utilities to advance the utilities concern of safeguarding its *stockholders* interest. However, Staff proposes an alternative approach to deal with the financial uncertainties involved due to unpredictable major and minor storm occurrences. OG&E requested a level of $5,588,111 in Storm Damage based on a four year non-major Storm related expenses, even though the *test year experience was only $1,852,997.* Staff s proposal of allowing a $3,000,000 level of storm expense will reduce OG&E s overall request by $2,588,111. Staff also supports the Company to establish a regulatory asset when the expenses go above $3.5 million.

**Alternative Financing of Other Working Capital Items**: Staff recommends that the Commission encourage OG&E and utilities in general to use short-term funds available for working capital needs. Staff recommends that the Commission approve alternative financing interest rate of 6 percent, instead of the tax-grossed-up Rate of Return in the range of 10.14% to 13.35% allowed in the Rate Base, to certain Working Capital Items and authorized Regulatory Assets. Staff is proposing the 6 percent, which is equivalent to OG&E s average long-term debt rate considering the volatility in the short-term interest rate.

**Prepaid Pensions**: The prepaid balance was generated when OG&E funded more than the annual expense booked for the cost of service purposes, to build up the fund assets to equal the accumulated benefit obligation. OG&E s funding of the under-funded benefit obligation provided benefit security to members, and prevented participant notices by funding to certain targets. Since OG&E finances the Prepaid Pension funding, Staff recommends that OG&E be allowed to recover a carrying cost at the rate of 6 percent. Staff has allowed a 13-month average balance of $52,893,979 instead of the year-end level of $67,156,464 requested by the Company, at a 6 percent interest to recover $3,173,639 annually in the cost of service.

**Tracking Mechanism for Pension Expense**: Pension Expense is a fluctuating item based on various actuarial assumptions, at any given time. Therefore, pension benefit account is an appropriate account for tracking, based upon any changes in assumptions and obligations. OCC had allowed in the past Regulatory Asset for Pension Expense at ONG s request. Staff recommends that the Commission consider the authorization of setting up both Regulatory Asset and Liability Accounts by OG&E to track the changes (increases and decreases) in pension

84

expense. However, the Commission should decide during each Rate Case what level to be allowed or disallowed.

**McClain Regulatory Asset Unamortized Balance**: First, Staff is proposing a 4-year amortization of Staff s recommendation, which is discussed in Mr. Thenmadathil s Pre-Filed Responsive Testimony. Second, these expense items should not get rate base treatment. Third, if the Commission decided to allow a return or carrying cost on an amortization asset it should be given only on each year s unamortized balance, rather than including the total beginning balance. Staff is recommending that the Commission allow a carrying cost of 6 percent on the average unamortized balance of $14,768,094. This will allow OG&E s recovery of $886,086 annually in the cost of service for this Regulatory Asset balance.

**Cash Working Capital**: Staff is recommending that the Commission approve alternative financing interest rate of 6 percent, instead of the tax-grossed-up Rate of Return allowed in the rate base, to the Cash Working Capital level of $34,667,976. This will allow OG&E to recover $2,080,079 annually in the cost of service for Cash Working Capital requirement.

**Prudence Issues Related to the Purchase of McClain Plant**: Based on the information reviewed by Staff related to the McClain Generation Plant, Staff is of the opinion that the purchase of McClain Generation Plant was a prudent decision. Staff s opinion is mainly based on the facts of comparing the purchased price versus the new building costs and the need for capacity by the Company. Staff did not conduct any independent study to determine the cost savings or increase to the ratepayers if OG&E continued to purchase power from other parties. However, when Staff compared the purchase price paid by OG&E per KW for the McClain Plant, which was under bankruptcy, to several other plants construction cost per KW, Staff is of the opinion that OG&E made a good purchase decision. Staff also wants to bring to the attention of the Commission that the OG&E s Transportation Contract with OGT has additional provisions for a Commodity Fee of $0.02 per MMBTU, and a provision for 1% Fuel Fee. The Commission had excluded OG&E s request for the Fuel Fee recovery of Enogex Contract from the customers, in a recent Order in Cause Number 200300226. Enogex s fuel factor based on their latest line loss study showed that it had come down from 1.52% to 0.47%.

**III. FINDINGS OF FACT AND CONCLUSIONS OF LAW**

**A. Jurisdiction**

The Commission finds that the Applicant is a public utility with plant, property, and other assets dedicated to the generation, production, transmission, distribution, and sale of electricity power and energy at wholesale and retail levels within the states of Oklahoma and Arkansas. Further, Applicant is Oklahoma Gas & Electric Company, a corporation incorporated within the State of Oklahoma, authorized to do business in the State of Oklahoma. This Commission has jurisdiction over this Cause by virtue of the provisions of Article IX, Sections 18 and following of the Constitution of the State of Oklahoma, 17 O.S. 2001, §§151 *et seq*., and the Rules and Regulations of this Commission, including the Commission s Minimum Standard Filing Requirements as set forth in OAC 165:70. Due and proper notice of these proceedings was given as required by law and the orders of this Commission.



---

**B. Test Year**

The Company proposed that the Commission base its review of the Company s rates and charges on financial data for the test year ended December 31, 2004, subject to certain pro forma adjustments for the addition of non-revenue producing plant through June 30, 2005. The Commission Staff conducted its audit of OG&E s books and records and prepared its testimony and exhibits based on December 31, 2004 data. None of the parties in this Cause have taken issue with the use of this test year. Consequently, the Commission finds that the test year ended December 31, 2004, is reasonably representative of OG&E s condition and operations, and provides an appropriate basis for the determination of its revenue requirements.

**C. Rate Base**

**1. Plant in Service**

a. **Utility Plant.** The Commission adopts Staff s proposal to reduce the utility plant in service by $35,742,734. Staff updated the plant in service balances based on the known and measurable changes occurring within the six-month post-test year period, June 30, 2005. Although the Company requested $138,258,631 for CWIP in the filing, the June 30 balance only reflects that $102,515,897 had been added to plant in service. Staff s adjustment is the difference between Staff s updated plant and what the Company requested in the filing for utility plant and CWIP.

b. **Holding Company Assets.** The Commission adopts Staff s proposal to increase the plant in service for holding company OGE Energy Corporation by $2,865,225. Staff proposed an increase related to the projects completed as of June 30, 2005, that were not included in the plant balance of the Company s current filing. Staff s recommended adjustment represents a net of the non-utility plant as included in the holding company plant totals in the amount of $10,824,978.

c. **Construction Work in Progress (CWIP).** The Commission adopts Staff s proposal to increase CWIP by $31,902,958. Staff recommended an increase in Plant in Service based on the TECO projects analysis as of June 30, 2005. These projects were deemed used and useful by the Company but were not yet transferred to plant in service on the Company s books as of June 30, 2005. Although $46,594,068 was listed as TECO, Staff disallowed 31.53% of the cost based on an estimation of the retirement, replacement and removal expenses, etc., associated with plant from December 2004 through June 2005. Based on the information provided by the Company at the time of hearing (October 2005), the July 2005 gross plant increased only by $16.5 million, and not by $46 million as requested by the Company. The Commission further finds that the Company shall improve internal accounting processes to ensure timely completion and transfer of all proposed current and future projects. The Commission further finds that the Company shall submit to the Director of the Public Utility Division and the Office of Attorney General, a detailed plan outlining the Company s proposed internal accounting processes for review. Such submission to the PUD Director and the Office of Attorney General, shall occur within six (6) months of the date of this Order.



---

d. **Accumulated Depreciation.** The **Commission** adopts Staff s proposal to increase accumulated depreciation by $38,071,196. Staff took into account the known and measurable changes occurring within six months of the test year-end when the accumulated depreciation balances were updated to the end of the six-month post-test year period. This is consistent with the treatment of updating plant in service for the six-month post-test-year period. This adjustment decreases the rate base by $38,071,196.

**2. Plant Held for Future Use (PHFU).**

The Company updated plant held for future use to the six-month post-test year period of June 30, 2005 in its rebuttal filing. The update changed PHFU from $928,968 (Schedule B-3, OG&E Application Package, Volume II, filed May 20, 2005) to $919,633 (Rebuttal Exhibit DRR-1R, Rebuttal Testimony of Don Rowlett*)*.

Based upon the record herein, the Commission adopts the Company s position and allows $919,633 as plant held for future use in the rate base of the Company.

**3. Pre-Paid Pension Obligation.**

The Commission adopts Staff s proposal to reduce prepaid benefits and obligations ( PBO ) by $67,156,464. (Mathai, prefiled testimony, pg. 24-29; pg.24, lines 13-21; pg.25, lines 1-11) (Malhotra, pre-filed testimony, pg. 21, lines 2-10) The Commission further adopts the Staff s proposal to allow a 13-month average balance of $52,893,979 but at a long-term cost of debt return of 6.03% resulting in a recovery to the Company of $3,189,506 annually in the cost of service, in Cause No. PUD 910001190, a levelized cost of debt was applied to deferred pension expense. The Commission does not adopt a carrying cost of 6% under the proposed Alternative Financing Methodology. The Commission further finds that the Staff shall convene a technical conference to discuss use of alternative financing and its benefits to ratepayers.

a. **Alternative Financing Interest Expense/General.** This determination results in a special interest expense on working capital of $3,189,507 related to the prepaid pension obligation.

**4. Cash Working Capital ( CWC ).**

The Commission adopts Staff s proposed ($6,661,270) be placed in the rate base for cash working capital. OG&E originally proposed $38,607,809 in cash working capital be included in rate base. The Company s proposal is supported by a lead-lag study sponsored by Mr. John A. Jeter. The Commission has consistently found that a lead-lag study is the most accurate method for calculating a cash working capital allowance. The Commission further finds inclusion of items in the CWC calculation be addressed in a technical conference by Staff.

The Commission notes that the Commission has ordered that the Staff shall convene a technical conference to discuss utilities use of short-term financing for working capital items and how its uses might achieve greater savings for rate payers. *See* Attachment C , p.4, ¶I to Order No. 512287 entered in Cause No. PUD 200400610. Absent a Stipulation regarding this issue, the Commission makes no determination regarding short-term financing.

87

---

On surrebuttal**,** Mr. Mathai of the Staff, provided oral surrebuttal testimony at the hearing. Specifically, he stated that the Revenue Requirement Exhibit he sponsored will change due to the changes proposed by Staff Witness Robert Thompson in the area of Cash Working Capital. The Commission accepts the restatement of Cash Working Capital at ($6,661,270) as proposed by the Staff, instead of the initially filed amount of $34,667,976. The change in Staff s calculation is based on the Deferred Fuel balance included in the cash working capital calculation. The Deferred Fuel Balance shall be addressed in the Company s FCA. The interest will be calculated for both under and over recoveries at the OCC approved interest rate for customer deposits held one year or less.

**5. Materials and Supplies.**

The Commission adopts Staff s proposal to reduce material and supplies by $1,347,435, which incorporated the known and measurable changes in the materials and supplies account occurring six-month post-test year. Staff used the 13-month average of actual inventory levels ending June 30, 2005, which produced a balance of $48,952,673. A 13-month average is typically used if balances are volatile, and forecasted amounts are used when the test year is based on projected data.

**6. Prepayments for EEI Dues and Economic Development Memberships.**

The Commission adopts Staff s proposal to reduce prepayments by $543,361. Staff excluded the prepayments made towards EEI dues and economic development membership fees from rate base rate of return treatment. Staff considered the EEI dues as a normal expense of doing business and noted EEI dues were included in the Company s miscellaneous expenses under cost of service.

**7. Fuel Inventories.**

a. **Coal Inventory.** The Commission adopts the Staff s proposal to reduce coal inventories by $7,417,846. The Company requested a 75-day burn inventory level. The Company does not currently have inventory at the 75-day burn level and due to delivery constraints associated with the Burlington Northern and Santa Fe Railroad, it is unlikely this level will be achieved. Staff recommended a 60-day target level coal inventory because it is an attainable inventory level for the Company in the near term. Staff s recommended level would be approximately 1,980,000 tons or $30,545,766 at an average cost of $15.43 per ton. The Company and the OIEC agreed to Staff s recommended 60 day burn as a reasonable level. The Commission adopts Staff s $7,417,846 adjustment to the Company s proposed coal inventory amount.

b. **Fuel Oil Inventory.** Staff agreed with the Company that fuel oil is a good hedge against natural gas volatility, but initially found disagreement with the level being sought by the Company. Staff recognized that the Company did not increase their fuel oil inventory when gas prices were rising to take advantage of the scenario advocated in Mr. Holloway s testimony. Staff also acknowledged that the price of fuel oil is increasing and adopted an increased per unit (average) cost in order to reflect the current higher cost to increase inventory



---

supply. Staff used the 13-month average of fuel inventory, and such calculation produced a level of 10,224,778 gallons at an average price of $0.543 per gallon for a total of $5,552,055. However, Staff later agreed with the Company s position that using an estimated replacement oil price of $0.85/gallon, the additional Number 6 fuel oil needed to equal a 16-day burn would increase Staff's adjustment by $1,957,808. At the hearing, Staff agreed to a fuel oil inventory value in this case of $7,509,863, based on the 2004 year-ending balance on this basis. The Commission adopts Staff s recommendation.

c. **Gas In Storage.** The Commission adopts Staff s proposal to accept the Company s recommendation of a current gas inventory of 2,200,000 MMBtu s, or a total of $7,870,576, at an average price of $3.578 per MMBtu for gas in storage. OG&E proposed an adjustment to this item to account for a reduced level of gas in storage from slightly over 8 Bcf to 7.5 Bcf. This resulted in a reduction of approximately $3 million to the test year end gas inventory. No party disagreed with this adjustment. Consequently, the Commission accepts the Company s recommendation.

**8**. **Accumulated Deferred Income Taxes.**

The Commission adopts the proposals of Staff, the Attorney General and the OIEC to increase accumulated deferred income taxes by $18,951,932. Specifically, Staff took into account the known and measurable changes occurring within the Company s accumulated deferred income tax account and updated it to the six-month post-test-year period ending June 30, 2005. The Commission adopts this approach as recognized and accepted by the Commission in Cause No. PUD 200400610. The approach takes into account the offsetting decreases in the investment levels related to plant in service, which had been updated to June 30, 2005.

**9.** **Regulatory Assets (Includes McClain Regulatory Asset)**

a. **McClain Regulatory Asset.** The Commission adopts the Company s proposal to include the McClain asset in rate base, subject to the following conditions as set forth in the Staff s proposal. (Thenmadathil Exhibit 18b):

The balance of $15,545,871, based on the average declining balance of the regulatory asset referenced above, amortized over a four year period will be allowed rate-base rate-of-return treatment. Short term financing is not adopted by the Commission. The Commission further requires the Staff to convene a technical conference to discuss use of alternative financing and its benefits to ratepayers. Recovery will cease at the end of four (4) years. The aggregate result of this adjustment is a decrease in Rate Base by $12,937,983, instead of the Staff s original decrease adjustment of $28,483,854.

(1) OG&E proposed a regulatory asset for recovery of the specified expenses listed in Paragraph 3 of the Joint Stipulation and Settlement Agreement approved by the Commission in Order No. 470044 issued in Cause No. PUD 200100455 (the 455 Stipulation ). The amount of the regulatory asset was calculated to be $24,419,019, the actual value of the expenses specified in Paragraph 3, as indicated on OG&E s books as of June 30, 2005. [Exhibit H-21]



In his rebuttal, Mr. Rowlett reviewed the 455 Stipulation and testified that one of its key features was the creation of a regulatory asset to mitigate the regulatory lag inherently associated with a large investment such as a power plant. He stated that the twelve-month period for accrual of the regulatory asset was to allow OG&E to accumulate some valuable cost of operations history for the acquired plant, to assist in evaluating the appropriate level of operating costs to be included in the cost of service in this case. Mr. Rowlett also testified that according to the language of the 455 Stipulation, the accrual period was meant to begin to run subsequent to the date of OG&E s acquisition and initial operation of the New Generation facility. The accrual period for the regulatory asset referenced in Paragraph 3 did not begin to run until OG&E both acquired and began initial operations of the facility. The Attorney General s witness interprets the provisions of Paragraph 2, which were litigated in Cause No. PUD 200400004, to reference only the acquisition of the facility.

The contentions of the Attorney General s witness and the OIEC are based upon a construction of the 455 Stipulation that acquisition referenced in Paragraph 2 is synonymous with acquisition and initial operation in Paragraph 3.

The Commission construes the provisions of Paragraph 3 to mean that before the regulatory asset can begin to accrue amounts, OG&E must have both acquired and begun initial operations of the McClain facility. Construing the term acquisition in Paragraph 2 to be synonymous with the phrase acquisition and initial operations in Paragraph 3 would require the Commission to ignore the differences between the language in these paragraphs. Paragraph 2 is not in issue here and Paragraph 3 provides that OG&E must both acquire and begin initial operations before the accrual period can begin. The contentions of the Attorney General s witness and of OIEC would preclude much or all of the accrual because the accrual period would begin before OG&E was operating the plant and thus before it could legally book to the regulatory asset any of the operating expenses referenced in Paragraph 3.

The Commission further finds that Paragraph 3 of the 455 Stipulation is very specific as to what costs should be included in the regulatory asset. The 455 Stipulation does not provide for purchased power costs to offset any amounts to be recovered in the regulatory asset. The Commission finds that purchased power expense is not covered in Paragraph 3 as a cost to be recovered in the regulatory asset.

Finally, the Commission finds that the reduced return on this asset based on the Staff s proposal for alternative financing should not be accepted based on the reasons set forth above.

Based on the foregoing, the Commission finds that operating expenses accrued to the McClain regulatory asset for the period July 9, 2004 through July 8, 2005. The expenses so accruing are comprised of those items specifically listed in Paragraph 3 of the 455 Stipulation. The total amount accrued to the regulatory asset over this period is $24,873,394 according to the Company [Exhibit H-21], but for purposes of the regulatory treatment the Staff s proposal is accepted.

(2) Staff s proposal to reduce regulatory assets is recognized by the Commission. Staff s adjustment consists of:

90

---

1. OCC assessment fees of $446,935 and
2. Other regulatory assets of $2,176,110.

1. OCC Assessment Fees. The Commission also adopts Staff s proposal to remove the accrual of OCC assessment fees from the rate base in order to expense assessment fees as any other normal business expense.

2. Other Regulatory Assets. Finally, Staff updated the balances for all other regulatory assets to the six-month post-test-year period ending June 30, 2005, to account for all known and measurable changes.

**10. Regulatory Liabilities**

The Commission adopts Staff s proposal to increase rate base by $1,394,502. Staff updated the regulatory liabilities to reflect the balances as of the six-month post-test-year period ending June 30, 2005.

**D. RATE OF RETURN**

**1. Capital Structure and Overall Rate of Return**

The Company proposed that its rates be set on the basis of its actual capital structure as of December 31, 2004, the close of the test year. Dr. Murry s Schedule DAM-21 sets forth OG&E's actual capital structure as consisting of 44.31% debt and 55.69% of common equity. Mr. Farrar, testifying for the Commission's staff, and Mr. Dunn, testifying for the OG&E Shareholders, agree that OG&E s actual capital structure should be used for ratemaking. Dr. Murry stated that OG&E's actual average debt cost was 6.03%.

Mr. Thornton testifying for the OIEC and Mr. Solomon testifying for the Attorney General contended that the consolidated capital structure of OGE Energy, OG&E's corporate parent, should be used instead. Mr. Thornton set forth various reasons for using the consolidated capital structure of OGE Energy and its subsidiaries. After review of those assertions, the Commission finds that the evidence supports its determination not to substitute an imputed capital structure for OG&E s actual capital structure.

In Commission Order No. 380443, Cause Nos. PUD 900000898, 910001055, 900001005, the Commission set forth:

The Commission, therefore finds that for periods prior to the date of this Order, the unconsolidated capital structures of OG&E and Enogex should be used; from and after the date of this Order, prospective rates shall be determined utilizing the consolidated capital structure of the Company.

At the time of that decision, OGE Energy, the holding company for OG&E and Enogex, had not yet been formed. One of the principal reasons for authorizing the holding company was

91

to insulate the ratepayers of OG&E from the business and financial risks incurred by Enogex and other unregulated activities of the consolidated group. Commission Order No. 399818, Cause No. PUD 950000148, a Memorandum of Understanding, Exhibit A, [10a.], 1996.

It was contended in this case, however, that because the ALJ in Cause No. PUD 200400610 (Oklahoma Natural Gas ( ONG or Oklahoma Natural )) used the consolidated ONEOK capital structure for setting rates, the same approach should also be used in this Cause. However, ONG is not a subsidiary of ONEOK, but rather an operating division that has no capital structure of its own. Hence, in the ONG case the only capital structure that could be used was that of ONEOK. Ms. Deborah Fleming, witness for OG&E, persuasively pointed out in her rebuttal testimony that OG&E has its own separate capital structure. OG&E also has its own bondholders, issues its own debt, maintains its own financial statements, maintains its own borrowing limits, has its own revolving credit facility and has its own bond rating. Mr. Dunn, testifying for the OG&E Shareholders, concurred and stated that a consolidated capital structure has no particular or necessary relationship to the appropriate capital structure for any individual subsidiary like OG&E.

The Commission finds that the capital structure for the Company should be utilized in setting rates for this proceeding consisting of 44.31% debt and 55.69% equity. The Commission finds that it is appropriate to use a return on common equity for OG&E of 10.75%, which when added to OG&E's actual capital structure as of December 31, 2004, results in an overall rate of return of 8.658%.

**2. Cost of Capital.**

**a. Cost of Debt.** The Commission finds that OG&E s cost of debt should be so reflected on Section F, Schedule 1, as adjusted by the Company s W/P F-3.1.

**b. Return on Equity.** Based upon the range of reasonableness presented in the evidence provided by the parties herein, the Commission finds 10.75% is the appropriate return on equity, which results in an 8.658% rate of return.

A number of experts presented analyses and schedules which could support an ROE of 7.4% to 12.0%. The Commission bases its finding on an assessment of the weight of the testimony. By its very nature, ROE is a subjective judgment, in part because the ROE decision is predicting the future. Mathematical formulas are involved (DCF and CAPM), but those formulas are replete with subjective judgments. Analysts must decide, among other things, which growth rate to use (dividend, earnings or book value), over what period of time in the future (i.e., 1 year, 5 years, 10 years), from what source (Value Line, Zachs, Thompson), and at what point in time (during the test year, when testimony is filed, the day of the hearing, for a single day, for multiple days in the year). Ultimately, the appropriate ROE is not a formula, but a value judgment.

First, the Commission was persuaded that the DCF dividend growth model is not as reflective of investor expectations as it once was. The testimony of Dr. Murry (p. 17, Direct of Dr. Murry) and Mr. Dunn (pp. 36-37, Responsive of John Dunn) that utility investors have become more focused on earnings growth and potential risk was particularly persuasive on this point. Therefore it may be risky from a regulatory standpoint to rely on a DCF dividend growth

92

model thus the DCF earnings growth model should have more weight. The CAPM models used by Mr. Farrar and Dr. Murry are important tests of reasonableness and should be given serious consideration.

Second, the Commission found helpful the testimony of Julie Cannell that A.G. Edwards and Lehman Brothers project expectations of an 11.5% and 11% ROE respectively for OG&E (p. 3, Rebuttal of Julie Cannell). The firms do not set the appropriate ROE, but they are one barometer of investor expectations for a reasonable ROE. Mr. Dunn testified that investors expect an ROE of not lower than 11.55%, which equals to the lower end of his DCF analysis and the ROE in OG&E's PUD 455 case (p. 3, Responsive of John Dunn).

However, with one exception discussed below, the Commission found merit in Mr. Farrar's straightforward analysis. The Commission finds it is therefore reasonable to average Dr. Murry's and Mr. Farrar's recommendations, which produces a return of 10.75%. Other calculations support the reasonableness of 10.75%. Indeed, an average of the recommendations of Mr. Thornton, Mr. Farrar, Dr. Murry and Mr. Dunn produces a similar average of 10.625%. Dr. Murry's Schedule DAM-5 in his direct testimony showed the Value Line projected ROE for the comparable companies used by Mr. Farrar and Dr. Murry; and the average ROE expectation for the years 2004 through 2010 was 10.825%. Dr. Murry's size adjusted CAPM model (DAM-19) produced an 11.77% return for the comparable companies, but the Commission found it instructive that the model produced a 10.74% return for OG&E. Mr. Farrar opposed Dr. Murry's size adjustment, but the testimony established that the Ibbotson size adjustment is reasonable (pp. 18-19, Rebuttal of Dr. Murry). If applied to Mr. Farrar's ROE calculation, the size adjusted CAPM rate is 11.55% (DAM R-9), which in turn changes Mr. Farrar's overall recommendation, found at ECF-5, to 10.43%. The Commission concludes, as suggested by Mr. Dunn (p. 43, Rebuttal of John Dunn) that Mr. Farrar's risk adjustment could be higher, raising his recommendation to the neighborhood of 10.75%.

Third, the Commission relies upon the recognition by the experts that ROE awards between 10% and 11% have occurred with some frequency in the past year, including a recent ROE award to Progress Energy of 11.75% (p. 253, October 11 Transcript). The Commission further notes however that an ROE of 10.75% is eighty (80) basis points less than the 11.55% ROE set for OG&E in Cause No. PUD200100455.

Finally, as pointed out by Mr. Hatfield in his rebuttal exhibit JRH-2R, the Commission recently found 10.75% to be a reasonable return in another matter. In Order No. 504841, issued on May 2, 2005, the Commission approved a Stipulation which authorized PSO to utilize an ROE rate of 10.75% for AFUDC and affiliate transaction purposes. The ROE was agreed to by the participants in that case. It should also be noted that Mr. Thornton, at pages 5, 6 and 7 of his Exhibit JST-1, concluded that PSO s parent company American Electric Power, consistently required a cost of equity which was more than 100 basis points lower than OG&E.

93

---

**E. OPERATING INCOME**

**1. Revenue.**[15]

OG&E proposed several revenue adjustments to Section H, Schedule H-2, as follows:

a. **Unbilled Revenue.** OG&E presented an adjustment for unbilled revenue to decrease test year revenue by $78,195,586. Unbilled revenue is the estimated revenue for service provided but not yet billed. Since these do not represent actual billed revenues, they should be excluded from test year revenues. Fuel cost lag represents the difference between the fuel cost collected in rates and the actual amount of fuel expense incurred. This amount can be positive or negative. The fuel lag represents the cumulative net difference of over-or-under collected fuel and purchased power costs at the end of a period. The Company has matched fuel expense with the associated pro forma test year revenues through adjustments to fuel expense and purchased power. Because this matching is done, the fuel cost lag amounts for the test year should be eliminated from test year revenues. This adjustment is the net sum of: (i) a decrease in unbilled revenue of $7,378,378, (ii) a decrease in revenue due to the fuel cost lag associated with the test year Rider for Fuel Cost Adjustment of $77,729,119 and (iii) an increase in revenues of $6,911,911