

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF)
OKLAHOMA GAS AND ELECTRIC COMPANY)
FOR AN ORDER OF THE COMMISSION) CAUSE NO. PUD 201100087
AUTHORIZING APPLICANT TO MODIFY ITS)
RATES, CHARGES, AND TARIFFS FOR RETAIL)
ELECTRIC SERVICE IN OKLAHOMA)

Direct Testimony

of

Donald R. Rowlett

on behalf of

Oklahoma Gas and Electric Company

July 28, 2011

Donald R. Rowlett
Direct Testimony

1 Q. **Please state your name, by whom you are employed, business address and the**
2 **position you hold.**

3 A. My name is Donald R. Rowlett. I am Director of Regulatory Policy and Compliance with
4 Oklahoma Gas and Electric Company (“OG&E” or “Company”). My business address is
5 321 N. Harvey, Oklahoma City, Oklahoma 73102.

6

7 Q. **Please state your educational qualifications and employment history with OG&E.**

8 A. I earned a Bachelor of Science degree in Business with an accounting emphasis (1980)
9 and a Masters in Business Administration (1992), from Oklahoma City University. In
10 1983, I became a Certified Public Accountant. Prior to joining OG&E, I was employed
11 by Arthur Andersen & Co. as a financial consultant and audit manager. During my
12 employment, I performed audits of financial statements in a variety of industries.
13 Additionally, I participated in the preparation of filings with the Securities and Exchange
14 Commission (“SEC”) and provided clients with guidance on the financial reporting
15 requirements of the SEC and Generally Accepted Accounting Principles (“GAAP”).

16

17 Q. **What are your responsibilities as Director of Regulatory Policy and Compliance?**

18 A. I am responsible for the analysis, development and communication of regulatory policy
19 for OG&E. This includes establishing policies to be followed by the Company in the
20 Oklahoma, Arkansas and Federal Energy Regulatory Commission (“FERC”) jurisdictions
21 and monitoring compliance with those policies throughout the Company. I have testified
22 on behalf of the Company before the Oklahoma Corporation Commission
23 (“Commission”), the Arkansas Public Service Commission (“APSC”) and the
24 Environmental and Public Works Committee in the United States Senate.

25

26 Q. **Please state the purpose of your testimony in this proceeding.**

27 A. The purpose of my testimony is to sponsor several accounting *pro forma* adjustments to
28 operating expense and rate base, as listed in Chart 1 below. I will also address
29 transmission construction projects that will be completed in 2012; the elimination of the

1 Off-system Sales of Electricity (“OSSE”) rider; the over/under fuel recovery interest
2 calculation in the FCA and the O&M benchmarking studies conducted by Mark Lowry of
3 the Pacific Economics Group (“PEG”). Dr. Lowry will provide testimony in this
4 proceeding as well.

5 **Chart 1**

<i>Pro Forma Adjustment</i>	Description
WP H 2-17	<i>Ad Valorem</i> Taxes
WP H 2-18	Pension and Medical Costs
WP H 2-19	Pensions and Benefits
WP H 2-30	Southwest Power Pool Expense
WP H 2-31	Pension Regulatory Liability Adjustment
WP H 2-33	SPP Transmission Expense Recovered from LSEs
WP H 2-36	FCA Fuel Adjustment
WP H 2-38	Intracompany SPP Fees
WP H 2-46	Post Retirement Amortization
WP B 3-16	Adjusts Transmission Investment for Third Party Recoveries

6
7 SECTION I. *PRO FORMA* ADJUSTMENTS

8 Taxes

9 Q. **Please describe the purpose of the *pro forma* adjustment to *Ad Valorem* Taxes (WP
10 H 2-17).**

11 A. This is a *pro forma* adjustment to operating expenses. The purpose of this adjustment is
12 to update the test year level of *ad valorem* taxes the Company paid. The adjustment
13 increases the test year *ad valorem* taxes to a level expected to be incurred when new
14 electric rates are implemented. This adjustment results in an increase to property taxes by
15 \$9,877,064.

16
17 Q. **Please explain how *ad valorem* taxes are established.**

18 A. *Ad valorem* taxes paid by OG&E are one of the costs associated with property used in
19 providing electric service. As a public service company the valuation of OG&E’s

1 property upon which *ad valorem* tax rates are applied are established for the State Board
2 of Equalization in Oklahoma by the *Ad Valorem* Division of the Oklahoma Tax
3 Commission. This valuation is performed by the Tax Division of the Arkansas Public
4 Service Commission for the Company's property located in Arkansas. The process used
5 to value public service property in both states is substantially as described by the
6 Oklahoma Tax Commission:

7 The steps in the unit valuation process are as follows: (1) Discover the
8 qualified public service companies. (2) Estimate the unit value [using] all
9 three approaches to value: cost, income, and market (stock and debt). (3)
10 Allocate the appropriate portion of the unitary value to the State of Oklahoma.
11 (4) Distribute the total state assessed value to local taxing districts.¹
12

13 **Q. Please explain how adjustment WP H 2-17 to *Ad Valorem* Taxes is calculated.**

14 A. The adjustment recognizes first an increase in *ad valorem* taxes based upon the fair
15 cash value (i.e. unit value) of the Company that has been established by the
16 Oklahoma Tax Commission for 2011 and an estimate of the fair cash value to be set
17 by Arkansas. Based on these factors the 2011 *ad valorem* taxes are expected to be
18 approximately \$64.5 million. Next, the 2011 *ad valorem* tax level is increased by
19 \$5,343,061 to reflect the five year historic trend in the levels of increases in
20 valuations and the historic average increase in millage rates over the same period.
21 Just as in the last Oklahoma rate case, this *pro forma* adjustment reflects an increase
22 that the Company expects to experience in the year the rates go into effect and is
23 based on the trend of *ad valorem* tax increases experienced during 2007 through 2010
24 and expected to occur in 2011.

25
26 **Q. Please explain the federal and state income taxes contained in Section J that make
27 up the *pro forma* adjustment to income tax expenses.**

28 A. The Company is responsible for federal and state income taxes. Section J is an analysis
29 of the current and deferred income tax expenses. These schedules and workpapers
30 capture adjustments necessary to recognize differences in the timing of income and
31 expenses between book accounting and tax accounting. Adjustments necessary to

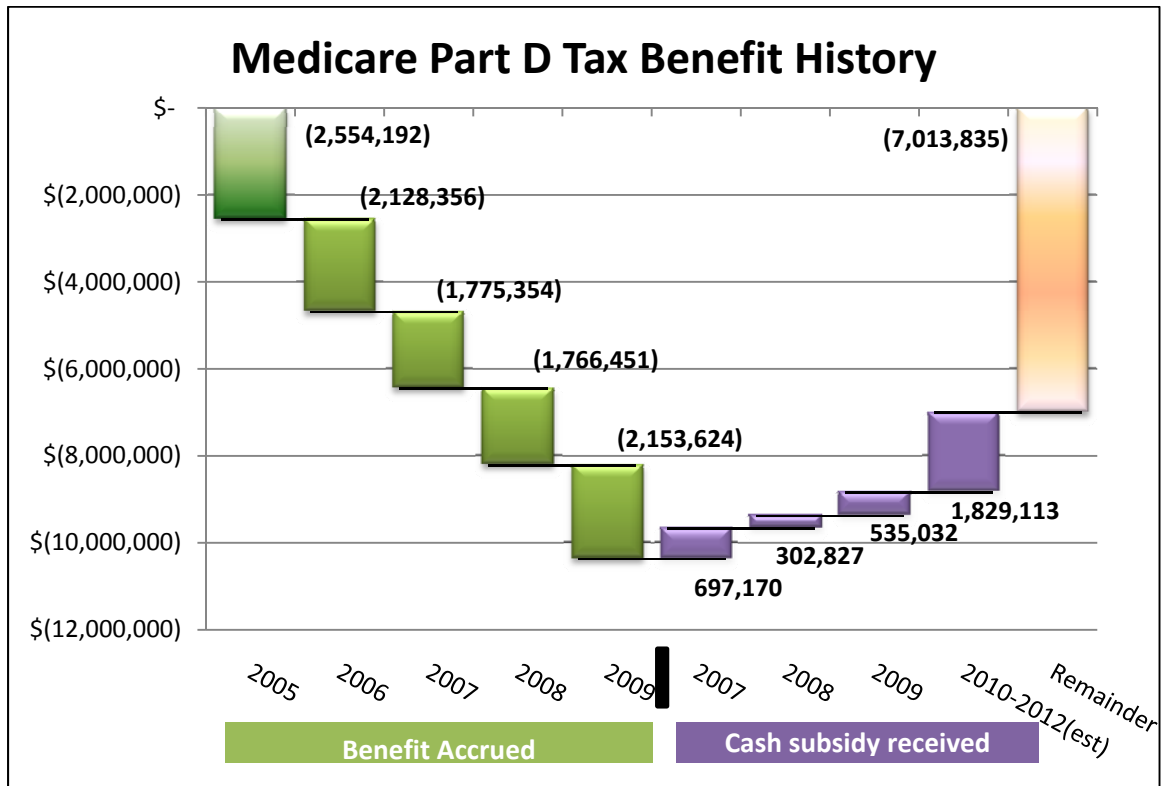
¹ Oklahoma *Ad Valorem* Forum, Volume XI, Issue IX, September 2002, page 3.

1 recognize permanent differences between taxable income and book income are also
 2 reflected on these schedules. Lastly, these schedules and workpapers reflect the impact
 3 that all other *pro forma* adjustments have on income tax expense. The resulting net
 4 decrease in income tax expense of \$43,265,544 for federal and state income taxes is
 5 reflected in Section J.

6
 7 **Q. Were there any unusual items that impacted income tax expense during the test**
 8 **year?**

9 **A.** Yes. The test year 2010 income tax expense level was unusually high due a change in the
 10 tax treatment of the Medicare Part D prescription drug coverage subsidy provided by the
 11 Federal government. The adjustment made by the Company to decrease the provision for
 12 income taxes to recognize the change in the tax treatment required by recent health care
 13 legislation is included in Section J and illustrated in Chart 2.

14 **Chart 2**



15 The green columns show the income tax benefits that OG&E has accrued related to the
 16 Medicare Part D subsidy from 2005-2009. The purple columns show the amount of non-

1 taxed subsidy actually and estimated to be received from 2007 to 2012. The column on
2 the far right side of the chart shows the accrued benefit reversed as a result of changes in
3 the law².

4 5 Pensions and Benefits

6 Q. **What are the *pro forma* adjustments related to pensions and benefits?**

7 A. There are four *pro forma* adjustments: WP H 2-18, Pension and Medical Costs; WP H 2-
8 19, Pensions and Benefits; WP H 2-31, Pension Regulatory Liability; and WP H 2-46,
9 Post Retirement Amortization.

10
11 Q. **How are benefit liabilities determined?**

12 A. Pension and medical expenses are the two primary benefits which can result in benefit
13 liabilities. To provide pension and medical benefits to its employees, OG&E has
14 established various employee benefit plans funded by employee and Company
15 contributions. Annually, the Company retains an independent actuary to prepare an
16 actuarial valuation of the pension and medical plans. Among other things, this valuation
17 determines the net periodic benefit cost which is the annual expense recognized by the
18 Company for GAAP accounting purposes. The valuation also documents the funded
19 status of the plan by comparing the projected benefit obligation to the fair value of assets
20 held by the plan. In 2011, the Company's independent actuarial firm, Mercer Inc.,
21 established the annual expense levels which form the basis for the *pro forma* adjustments.

22
23 Q. **Please explain the purpose of WP H 2-18, *pro forma* adjustment to Pension and
24 Medical Costs.**

25 A. Workpaper WP H 2-18 provides the basis for the *pro forma* adjustment to test year
26 pension, postretirement benefit, and active employee medical expenses.

27
28 Q. **How is WP H 2-18 calculated?**

29 A. The schedule compares the test year level of expenses to the 2011 level of these expenses
30 provided by Mercer. The schedule shows a decrease of \$2,011,065 and \$8,392,423 for

² Patient Protection and Affordable Care Act

1 pension and postretirement benefit expense, respectively and an increase of \$1,006,153
2 for active employee medical costs. The net *pro forma* adjustment decreases operating
3 expenses by \$9,397,336.
4

5 **Q. Please explain WP H 2-19, *pro forma* adjustment to Pensions and Benefits.**

6 A. WP H 2-19 shows that approximately \$628,000 of pension and benefit costs had been
7 incorrectly charged to certain operation and maintenance expense accounts. This
8 adjustment results in no net change to operating income.
9

10 **Q. Please explain WP H 2-31, *pro forma* adjustment, Amortization of Pension
11 Regulatory Liability.**

12 A. To the extent pension expense varies each year from the level of pension expense
13 authorized in the last rate case, a regulatory asset or liability is recorded. The regulatory
14 asset/liability balance increases or decreases between rate cases. At the end of the test
15 year the Company had recorded a regulatory liability of \$8,148,999 since the amount of
16 pension expense being recovered in rates exceeded actual pension expense. The
17 regulatory liability balance is projected to December 31, 2011 at which time it will be
18 \$18,469,993. The *pro forma* adjustment amortizes this liability over two years by
19 reducing the *pro forma* level of pension expense by \$9,234,997.
20

21 **Q. What has the Company done to control pension expense volatility?**

22 A. To protect both customers and investors from the volatility of pension expense levels, the
23 Company requested and received approval of a Pension Tracker in Cause No. PUD
24 200500151, Order No. 516261.
25

26 **Q. Has the Company proposed a similar treatment for retiree medical costs?**

27 A. Yes. On February 22, 2011, OG&E filed an Application in Cause No. PUD 2001100027
28 requesting that the Commission approve a modification to the current Pension Tracker to
29 include OG&E's retiree medical costs, beginning January 1, 2011. This modification
30 would allow the Company to track the difference between the levels of Retiree Medical
31 Expense authorized in OG&E's last rate case, Cause No. PUD 200800398, and the level

1 currently being incurred by the Company. A Settlement Agreement was executed on June
2 23, 2011 and contained two operative recommendations of the Stipulating Parties: (i) that
3 the Pension Tracker should be modified to include retiree medical costs as a component
4 of the costs tracked, effective January 1, 2011, and to remain in effect until further order
5 of the Commission; and (ii) that the underlying actuarial assumptions and ultimate level
6 of Retiree Medical Plan costs included in base rates be reviewed and determined in the
7 current rate case, Cause No. PUD 201100087. At the date of this testimony, a decision
8 on the recommendation of the ALJ approving the Settlement Agreement is pending at the
9 Commission.

10
11 **Q. If the Commission approves the Settlement Agreement recommending that retiree**
12 **medical costs be included in the pension tracker, will OG&E's retiree medical costs**
13 **in 2011 result in a regulatory liability?**

14 A. Yes. OG&E's retiree medical costs for 2011 will be less than the level for those costs
15 calculated in the Company's last rate case, resulting in a regulatory liability. The change
16 in the retiree medical expense level from the level established in OG&E's last general
17 rate review will be booked as a regulatory liability until placed in rates in a future rate
18 proceeding.

19
20 **Q. Has the Company estimated the 2011 regulatory liability which would be created by**
21 **the modifications to the Pension Tracker for retiree medical expenses?**

22 A. Yes, in WP H2-46 this amount has been calculated. As a result of the changes in retiree
23 medical benefits, the Company's 2011 retiree medical expense would be approximately
24 \$7.2 million, as compared to the total company authorized retiree medical cost level
25 approved in OG&E's last rate case of approximately \$11.1 million. In anticipation of the
26 Commission's authorization of the requested modification of the Pension Tracker, OG&E
27 has started accruing the Oklahoma jurisdictional portion of this difference, or
28 approximately \$3.5 million, as a regulatory liability as it accrues during 2011. The
29 resulting *pro forma* adjustment, WP H 2-46, would reduce operating expenses by
30 \$1,918,961. This amortizes the projected December 31, 2011 balance over 2 years.

1 Q. **What steps has the Company undertaken to mitigate increases in medical expenses?**

2 A. OG&E has implemented some shifting of costs from the Company to the employees and
3 retirees by increasing the participants' contribution amounts as well as minor plan design
4 changes. The Company has increased medical deductibles and implemented a
5 prescription deductible. The prescription co-payments have also been increased. New
6 employees are no longer eligible for retiree medical coverage. The claims administration
7 was transferred to Blue Cross, Blue Shield Custom Group Services, a claims
8 administrator who offers a preferred provider network with substantial negotiated
9 discounted services. The plan design provided significant incentives for members to use
10 providers in this network. Effective January 1, 2004, the reimbursement for network
11 provider services was reduced from 90% to 80% and the deductible per member was
12 increased to \$200. While OG&E has experienced increasing medical costs over the last
13 several years, these changes have resulted in significant savings to the plan when
14 compared to the national trend in medical costs.

15

16 Q. **What additional steps has OG&E taken to control medical costs?**

17 A. The Company's actions include cost shifting for retirees by moving them to a target cost
18 sharing of post-retirement medical benefits. For active employees, the Company has
19 moved from a co-pay system to a co-insurance structure and adjusted the benefit
20 reimbursement percentages. OG&E is also conducting an education campaign and
21 establishing a health internet portal to help our members to become better healthcare
22 consumers.

23

24 Q. **How do these pension and medical benefit adjustments impact OG&E's customers?**

25 A. Taken together, these four *pro forma* adjustments represent a reduction in operating
26 expenses of approximately \$20.5 million. These adjustments reflect tough decisions made
27 by the Company that hold down the costs to provide service. These actions are indicative
28 of the actions taken by the Company which result in what the Pacific Economics Group
29 report describes as "superior cost management" by the Company. I will discuss that
30 report in more detail later in my testimony.

1 FCA Fuel Adjustment

2 Q. **Please explain WP H 2-36, *pro forma* FCA Fuel Adjustment.**

3 A. The adjustment synchronizes the *pro forma* level of fuel expense included in operation
4 expenses with the *pro forma* level of operating revenues. OG&E witness Adam Bigknife
5 discusses the *pro forma* operating revenues. OG&E's fuel adjustment clause adjusts
6 operating expenses to reflect the level of actual fuel expense incurred, therefore it is
7 necessary to "true-up" fuel revenues and fuel expenses in determining *pro forma*
8 operating income. This *pro forma* adjustment decreases test year operating expenses by
9 \$80,211,855 to reflect the revenue and expense levels that the Company will experience
10 after new rates are implemented in January 2012.

11
12 Transmission Adjustments

13 Q. **What *pro forma* adjustments related to transmission plant and expenses is OG&E
14 requesting in this proceeding?**

15 A. Schedule H-3 of the MFR package contains two *pro forma* adjustments to operating
16 income (Southwest Power Pool Expense contained in WP H 2-30 and SPP Transmission
17 Expense Recovered from LSEs contained in WP H 2-33). The Southwest Power Pool
18 Expense adjustment is an increase in operating income of \$544,409 and the SPP
19 Transmission Expense Recovered from LSEs is a reduction to operating income of
20 \$611,105. In addition, Schedule B-4 of the MFR package contains a *pro forma*
21 adjustment to rate base, which is labeled "Adjusts Transmission Investment for 3rd Party
22 recoveries." This adjustment is a reduction to rate base of \$7,840,993. Finally, there is an
23 elimination adjustment for Intracompany SPP Fees (WP H 2-38). These adjustments are
24 discussed in detail below.

25
26 Southwest Power Pool Expense Adjustment

27 Q. **Please describe the SPP Expense *pro forma* adjustment (WP H 2-30).**

28 A. This adjustment is comprised of two separate components. First, as required by the order
29 issued in Cause No. PUD 201000146, OG&E is removing from base rates certain
30 transmission costs incurred during the 2010 test year. Although explained in greater
31 detail below, these costs relate to costs (i) associated with transmission upgrades and

1 facilities that have been approved by the SPP in its regional planning processes and
2 constructed by non-OG&E transmission owners throughout the SPP; and (ii) that have
3 been allocated to OG&E by the SPP (under the SPP open access transmission tariff) and
4 through FERC-approved transmission rates. These costs are referred to as “Third Party
5 Owned Transmission Costs.” These Third Party Owned Transmission Costs will be
6 removed from base rates so that such costs will pass through the SPP Cost Tracker
7 (approved in Cause No. PUD 201000146). The second component of this *pro forma*
8 adjustment relates to updated SPP and NERC fees including the SPP Administrative Fee
9 which will be paid by OG&E during 2012. Together these two components result in a
10 net increase to operating income of \$544,409.

11
12 *Component Related to Third Party Owned Transmission Costs*

13 **Q. Please discuss the Commission’s order in Cause No. PUD 201000146.**

14 A. In Order No. 583894, the Commission found that OG&E was authorized to recover Third
15 Party Owned Transmission Costs (as defined above). The Commission further found that
16 the SPP Cost Tracker was the appropriate mechanism for recovering Third Party Owned
17 Transmission Costs from Oklahoma retail customers. The SPP Cost Tracker was made
18 effective January 1, 2011.

19
20 **Q. Did the Commission order make a finding regarding how the SPP Cost Tracker
21 would work prior to and after OG&E’s 2011 general rate case?**

22 A. Yes. Since there is a small amount of Third Party Owned Transmission Costs included in
23 OG&E’s base rates, the Commission order made it clear that recovery through the SPP
24 Cost Tracker in 2011 would not include those costs.

25
26 **Q. Did the Commission order make a finding regarding how recovery of the Third
27 Party Owned Transmission Costs would be addressed in the present general rate
28 case proceeding?**

29 A. Yes. The Commission order found that in its 2011 general rate case OG&E would
30 remove all Third Party Owned Transmission Costs from base rates so that, beginning in
31 2012, 100 percent of these costs will be recovered through the SPP Cost Tracker.

1 Q. **Has OG&E made an adjustment to remove the Third Party Owned Transmission**
2 **Costs from the 2010 test year?**

3 A. Yes. The adjustment is identified on Line 46 of WP H2-30 and equals a reduction from
4 the total SPP expense of \$2,643,631.

5

6 *Second Component Related to SPP and NERC Fees*

7 Q. **Please elaborate on the second component of the *pro forma* adjustment for SPP and**
8 **NERC fees?**

9 A. WP H 2-30, *pro forma* adjustment to Southwest Power Pool Expense contains the details
10 associated with this adjustment. This component reflects an overall increase in SPP
11 expense of \$3,188,040.

12

13 Q. **How is this \$3,188,040 increase calculated?**

14 A. This amount reflects adjustments to several different SPP schedules and the annual
15 NERC assessment. These individual adjustments are identified in column 7, 8, 9 and 10
16 of WP H 2-30.

17

18 Q. **What does the adjustment identified in Column 7 represent?**

19 A. This column identifies the *pro forma* adjustments to SPP's Schedule 1 charges for 2011.
20 Schedule 1 is a SPP charge that OG&E incurs because it has load on another
21 Transmission Owner's system and must pay that Transmission Owner an ancillary
22 service fee for scheduling, system control and dispatch. Since OG&E has a small amount
23 of load on the Western Farmer's transmission system, it must pay this small charge.
24 During the test year, OG&E accrued a credit for this expense due to a one-time
25 overestimate of such costs in the 2010 test year. In order to normalize this expense,
26 OG&E includes a *pro forma* adjustment increase of \$129,979. This adjustment is
27 reflected on Line 45 of WP H 2-30.

28

29 Q. **What does the adjustment identified in Column 8 represent?**

30 A. This column identifies the *pro forma* adjustments to the SPP Schedule 1A Administrative
31 Fee. This Administrative Fee supports the costs incurred by SPP in administering the SPP

1 Open Access Transmission Tariff (“OATT”) and conducting its operations. These costs
2 are related to all SPP activities, including but not limited to employees, scheduling of
3 transmission service, transmission planning, market facilitation, maintenance of facilities,
4 information technology and outside consulting. According to projections received from
5 the SPP, this SPP Administrative Fee is expected to increase significantly in the coming
6 years due primarily to the implementation of the Day Ahead Market. In fact, SPP plans to
7 increase the fee incrementally over the next several years. In the 2010 test year, this fee
8 was set at 19.5 cents per MWh of load for each LSE taking service in the SPP. In a
9 presentation made to the SPP Board of Directors in October 2010, the SPP’s Finance
10 Committee recommended an increase in the Administrative Fee from 19.5 cents per
11 MWh to 21 cents per MWh in 2011. The Finance Committee’s projected level for the
12 Administrative Fee beginning in January 2012 is 25.5 cents per MWh. The October 2010
13 Finance Committee recommendations are attached hereto as Exhibit DRR-1.
14

15 **Q. Was the increasing SPP Administrative Fee a subject of settlement in Cause No.**
16 **PUD 201000146?**

17 **A.** Yes. In that case, OG&E had sought recovery of the SPP Schedule 1A Administrative
18 Fee through the SPP Cost Tracker. However, in the order approving the settlement
19 reached by the parties to that cause, the Commission found that OG&E would not collect
20 its SPP Administrative Fee through the SPP Cost Tracker. However, the Commission
21 found that OG&E may seek cost recovery for such fee in its general rate cases.
22 Moreover, the Commission found that the most recent SPP projection of the 2012 SPP
23 Administrative Fee provided by the SPP on or before June 30, 2011 may be used as the
24 basis for determining a *pro forma* adjustment to the test year level of SPP Administrative
25 Fees in the 2011 general rate case for rates becoming effective in 2012.
26

27 **Q. What is the amount of the increase to the SPP Administrative Fee?**

28 **A.** Based on the Finance Committee’s projections in October 2010, OG&E adjusted the
29 2010 test year Schedule 1A Administrative Fee from \$7,563,299 to \$9,913,703 for an
30 overall increase of \$2,350,404.

1 Q. **What does the adjustment identified in Column 9 represent?**

2 A. This column identifies the *pro forma* adjustments to the SPP Schedule 9. This SPP charge
3 is paid by OG&E when it uses another Transmission Owner's facilities to reach its load.
4 OG&E incurs this charge because the Oklahoma Municipal Power Authority owns
5 transmission assets integrated within the OG&E transmission system and OG&E utilizes
6 those facilities in its transmission system operations. A Schedule 9 charge is also
7 incurred to allow OG&E to serve its load located on the Western Farmers' system. This
8 Schedule 9 fee is not included in the SPP Cost Tracker and has been retained in base
9 rates. During the test year, OG&E accrued a credit for this expense due to a one-time
10 overestimate of such costs in the 2010 test year. In order to normalize this expense,
11 OG&E includes a *pro forma* adjustment increase of \$458,925. This adjustment is
12 reflected on Line 45 of WP H 2-30.

13

14 Q. **What does the adjustment identified in Column 10 represent?**

15 A. This column identifies the *pro forma* adjustments to the NERC Assessment. The NERC
16 Assessment is a charge imposed on OG&E to satisfy its share of both the NERC annual
17 budget and the annual budget of the Regional Entity ("RE"). The SPP is the RE
18 responsible for regional reliability in this area. OG&E has identified an increase in the
19 NERC Assessment for 2011. This charge will increase from \$1,265,307 in the 2010 test
20 year to \$1,514,040 during 2011. Therefore, OG&E has included an adjustment of
21 \$248,733 on Line 45 of WP H2-30.

22

23 Q. **Can you please explain why the total *pro forma* adjustment for SPP Expense is
24 \$544,409 when the adjustments identified in column 7, 8, 9, and 10 total \$3,188,040?**

25 A. As mentioned above, there is \$2,643,631 of Third Party Owned Transmission Costs that
26 is being removed from the 2010 test-year SPP expense. So, this amount is subtracted
27 from the \$3,188,040 *pro forma* increase to SPP expense to reflect a net increase of
28 \$544,409 for the overall SPP expense *pro forma* adjustment. Essentially, WP H 2-30
29 calculates a total *pro forma* adjustment that includes both of the two categories of pro
30 form adjustments discussed above.

1 *Adjustments Related to Regionally Allocated OG&E Plant and Expense*

2 Q. **Why is OG&E proposing *pro forma* adjustments related to regionally allocated**
3 **transmission plant and expenses?**

4 A. OG&E proposes *pro forma* adjustments to remove certain OG&E transmission plant and
5 associated transmission O&M expense from base rates. These adjustments reflect the
6 fact that the revenue requirement associated with regionally allocated transmission plant
7 and expense will be assigned to other load serving entities (“LSEs”) around the SPP and
8 will not need to be recovered from OG&E’s customers.

9
10 Q. **What are these *pro forma* adjustments?**

11 A. As mentioned above, OG&E makes a *pro forma* adjustment to operating income labeled
12 “SPP Transmission Expense Recovered from LSEs” contained in WP H 2-33 and a *pro*
13 *forma* adjustment to rate base labeled “Adjusts Transmission Investment for 3rd Party
14 recoveries” contained in WP B 3-16.

15 The adjustment reflected on WP B 3-16 is a reduction to rate base of \$7,840,933. This
16 amount includes adjustments to Transmission Investment and Accumulated Depreciation,
17 M&S, ADIT and an additional adjustment to Transmission Investment to reflect the
18 removal of a percentage of regionally allocated transmission projects that were placed in
19 service during the first half of 2011.

20 The adjustment on WP H 2-33 is a \$611,105 reduction to operating expenses
21 (Transmission O&M, A&G Expense, Depreciation Expense and Taxes Other Than
22 Income).

23
24 Q. **Please explain why OG&E is proposing adjustments to its transmission plant and**
25 **related operating expenses.**

26 A. As explained above, one of the significant ramifications of regional cost allocations is
27 that costs associated with certain transmission projects that SPP directs OG&E to build
28 will be spread around the SPP footprint to other LSEs. By doing so, SPP recognized that
29 various LSEs within the SPP would benefit from OG&E transmission upgrades and
30 expansion. For example, SPP may require OG&E to build a certain transmission line and,
31 because the entire SPP footprint benefits from this new OG&E line, a portion of the cost

1 responsibility for OG&E's revenue requirement would shift from OG&E's customers to
2 the other benefiting LSEs in the SPP. To recognize that other LSEs are responsible for a
3 portion of this revenue requirement, OG&E is reducing the cost responsibility of
4 Oklahoma customers by removing certain transmission costs from rate base and O&M
5 expense. These costs and expenses will be recovered by OG&E from the SPP through
6 FERC approved transmission rates.

7
8 **Q. How did OG&E determine what regionally allocated costs to remove from rate base
9 and O&M expense in the Oklahoma jurisdiction?**

10 A. OG&E used cost information contained in its FERC approved transmission formula rate.
11 Specifically, the costs to be removed from rate base and O&M expense were based on
12 updated data contained in OG&E's FERC-approved Transmission Formula Rate and filed
13 with the FERC in June 2011. This Transmission Formula Rate reflects actual FERC Form
14 1 data. Two calculations were made in order to remove appropriate costs from rate base
15 and O&M expense in Oklahoma.

16
17 **Q. What was the first calculation?**

18 A. OG&E used the revenue requirement calculated by the FERC Transmission Formula
19 Rate for the regionally allocated projects. It divided the projected revenue to be collected
20 from others during 2011 by the sum of the net revenue requirements of all regionally
21 allocated OG&E projects (\$1,657,216/\$3,355,787) to determine the percentage of the
22 revenue requirement paid by LSEs other than OG&E (*i.e.*, 49.38 percent). Since others
23 were responsible for 49.38 percent of the revenue requirement for these regionally
24 allocated projects, OG&E used this percentage to remove 49.38 percent of the
25 Transmission Investment, Accumulated Depreciation and Depreciation Expense for
26 regionally allocated projects from 2010 test year rate base.

27
28 **Q. Please explain the second calculation.**

29 A. The second calculation is derived also from the Company's updated Formula Rate
30 calculation. By dividing the revenue from others for regionally allocated OG&E projects
31 by the total Annual Transmission Revenue Requirement ("ATRR") from the OG&E

1 transmission formula rate (\$1,163,489/\$89,809,440), the resulting 1.30% was applied to
2 M&S, ADIT, Transmission O&M, A&G Expense and Taxes Other Than Income
3 amounts reflected in the formula rate template.
4

5 **Q. Has OG&E included 2011 transmission related costs in this general rate**
6 **proceeding?**

7 A. Yes. OG&E has begun construction on several new transmission projects. As explained
8 by Witness Sheri Richard, OG&E has constructed numerous transmission and
9 distribution projects that have been placed in service in 2011 or are expected to be placed
10 in service before September 30, 2011. These projects are detailed on WP B 3-6 through
11 WP B 3-9 and are reflected as *pro forma* adjustments to rate base.
12

13 **Q. Did OG&E apply the method of calculation for regionally allocated projects to**
14 **certain transmission projects placed in service in 2011?**

15 A. Yes. OG&E placed two regionally allocated transmission projects in service in 2011.
16 These projects are included in rate base through *pro forma* adjustments contained in WP
17 B 3-6 through WP B 3-9, which are supported by OG&E witness Sheri Richard. Because
18 these are regionally allocated projects and OG&E's customers would not be responsible
19 for the entire revenue requirement for these projects, OG&E has included a further
20 adjustment to remove a percentage of the investment in these projects from rate base.
21

22 **Q. What are these regionally allocated projects that were placed in service in 2011?**

23 A. First, OG&E rebuilt and performed some reconductor work on the Ardmore to Rocky
24 Point 69kV line. This project involved \$499,844 of transmission investment, which was
25 placed in service in June 2011. Second, OG&E installed a 69 kV, 9MVar capacitor bank
26 at its Tiger Creek Substation. The project involved \$332,308 of transmission investment,
27 which was placed in service in February 2011.

1 Q. **How did OG&E calculate the percentage of these investments to be removed from**
2 **rate base?**

3 A. OG&E calculated that 36.49% of the revenue requirement for these projects will be paid
4 by others in the SPP. Thus, OG&E removed 36.49% of the total transmission plant for
5 these projects from rate base in Oklahoma. This percentage is different from the 49.38
6 percentage described above and used for transmission investment already in base rates
7 because OG&E has been assigned a different allocation of costs for these two projects
8 under the SPP regional allocation methodology. This adjustment is reflected on Line 4 of
9 WP B 3-16.

10

11 Q. **Please explain the purpose and the impact of the adjustment WP H 2-38,**
12 **Intracompany SPP Fees.**

13 A. During the test year, OG&E was billed approximately \$102 million by the SPP for
14 certain services it provided. The Company received an equal amount from the SPP which
15 was booked as revenues for use of its facilities to provide these services. An adjustment
16 was made to eliminate these expenses and a corresponding adjustment was made to
17 eliminate the associated operating revenues. These adjustments do not have a net impact
18 on the overall revenue requirement.

19

20

SECTION II: OTHER MATTERS

21

2012 Transmission Projects

22 Q. **Has OG&E identified regionally allocated transmission projects that will be**
23 **completed in 2012?**

24 A. Yes. OG&E is currently constructing two large transmission projects, the cost of which
25 will be regionally allocated. The Sunnyside-Hugo Project (“Sunnyside-Hugo”) is a 345-
26 kV, 120-mile transmission line to be built from OG&E’s Sunnyside substation to the
27 Western Farmers Electric Cooperative’s Hugo Generation Plant, as well as associated
28 upgrades to the Sunnyside substation. Sunnyside-Hugo is estimated to cost \$151.5
29 million and has an estimated in-service date of April 1, 2012. The Sooner-Rose Hill
30 Project (“Sooner-Rose Hill”) is a 345-kV, 88-mile transmission line to be constructed
31 from OG&E’s Sooner substation to Westar Energy’s Rose Hill substation near Wichita,

1 Kansas. The OG&E portion of the Sooner-Rose Hill line is 43 miles in length, will
2 terminate at the interface with the Westar Energy segment at the Oklahoma-Kansas state
3 line, is estimated to cost \$43.7 million, and has an estimated in-service date of June 1,
4 2012.

5
6 **Q. Why is OG&E constructing these two projects?**

7 A. Projects vetted and selected through SPP's planning processes strengthen the reliability
8 of SPP's system and provide regional benefits by relieving congestion that already exists
9 or that will exist due to requests for new transmission service. SPP completed its 2009
10 SPP Transmission Expansion Plan ("STEP") in January 2010 pursuant to the planning
11 processes set forth at Attachment O and Attachment Z1 of the SPP OATT. The 2009
12 STEP includes a regional reliability assessment for the period of 2010 to 2019 and
13 identifies needed transmission upgrades and possible problems in both normal and
14 contingency conditions.³ The 2009 STEP highlights the region's top congested flowgates
15 and identifies priority projects that will lower production costs and relieve congestion.⁴
16 Both of the above projects were evaluated and approved by SPP through regional
17 planning processes and subsequently included in the 2009 STEP. The SPP Board of
18 Directors has approved both of the projects, and SPP has issued a Notification to
19 Construct for each project.

20
21 **Q. How were the projects evaluated in the 2009 STEP?**

22 A. Within its overall transmission planning process, SPP uses several distinct evaluation and
23 approval processes to determine the need for new transmission infrastructure. Each of
24 the relevant processes is described in the STEP Report. For these particular projects, SPP
25 conducted studies under Attachment Z1 of the SPP OATT to identify, among other
26 things, transmission expansion projects needed to address the reliability and/or
27 congestion concerns created by new requests for transmission service. Accordingly, SPP
28 combines all requests for transmission service that it has received, identifies all system
29 constraints, and then determines "the upgrades required to reliably provide all of the

³ 2009 STEP, at p. 2.

⁴ *Id.* at 2-3.

1 requested service.”⁵ This practice is intended to allow SPP and participating stakeholders
2 to “develop a more efficient expansion of the transmission system” that will provide the
3 necessary capacity to resolve congestion and reliability problems and do so at the
4 minimum total cost to beneficiaries.⁶ As an additional component to this process, SPP
5 conducts a regional review to determine if alternative solutions would reduce overall cost
6 to customers (*i.e.*, through congestion reduction, greater efficiencies, *etc.*).⁷ Upgrades
7 identified through this study process were then included in the 2009 STEP.

8
9 **Q. What were the ultimate findings of the 2009 STEP?**

10 A. In the end, SPP found that limiting constraints existed on SPP’s system that would
11 prevent requests for transmission service from being granted unless upgrades are made to
12 the transmission system. These necessary upgrades include Sunnyside-Hugo and Sooner-
13 Rose Hill.⁸ SPP then designated OG&E as the appropriate Transmission Owner to
14 construct, own, and/or finance those projects in the STEP.

15
16 **Q. Has there been a STEP approved by SPP since the 2009 STEP and did it make any
17 changes to the two projects?**

18 A. A 2010 STEP was approved in January 2011, but it confirmed the need and benefits
19 associated with the two projects.

20
21 **Q. Is OG&E proposing a cost recovery mechanism for these two projects?**

22 A. Yes. OG&E believes that when these projects are placed in service in 2012, the costs
23 should be recovered through the existing Renewable Transmission Systems Additions
24 (“RTSA”) rider. This would require minor changes to the RTSA and those changes are
25 sponsored by OG&E witness Greg Tillman.

⁵ See SPP OATT, Attachment Z1, Sections III.a.

⁶ See SPP OATT, Attachment Z1, Sections I.

⁷ See SPP OATT, Attachment Z1, Sections III.a.

⁸ See 2009 STEP at p. 7

1 Q. **Why is timely recovery through a rider important for OG&E for these two**
2 **projects?**

3 A. Without this recovery, costs for these projects will not be included in Oklahoma rates
4 until after the 2013 general rate case. Timely recovery of this investment through a rider
5 will greatly assist OG&E and its customers when the Company finances other projects
6 that are being constructed over the coming years. Between now and 2014, OG&E will be
7 constructing nearly \$1 billion in 345 kV transmission lines (in addition to the other new
8 plant needed to serve customers). The size of that investment will present a number of
9 financial challenges for OG&E. First, funding projects of this size and scope will require
10 significant outlays of cash, decreasing OG&E's cash flow. Second, these expenditures
11 will increase OG&E's debt and will burden OG&E's financial metrics, raising the risk of
12 a credit downgrade. Third, internal competition for capital with other OG&E
13 expenditures raises additional financing challenges. Fourth, the long lead times associated
14 with the Projects will compound each of these risks. Reducing the risks results in lower
15 borrowing costs and ultimately benefits our customers.

16
17 Q. **Please describe the impact on cash flow of the projects.**

18 A. The large \$1 billion in investment over the next several years will depress OG&E's cash
19 flow during the construction phase of the projects. Over the next four years, OG&E will
20 face a negative cash flow position as a result of meeting the extensive level of capital
21 expenditures required by the projects. Cash flows generated from operations will not be
22 sufficient to cover these transmission projects. The decreased cash flow will put stress on
23 OG&E's credit metrics. A decreased cash flow increases the risk that a utility may not be
24 able to satisfy its financial obligations and can harm a utility's credit ratings. A 2010 S&P
25 report highlighted the importance of cash flow in connection with large-scale capital
26 projects:

27 **Especially during upswings in the capital expenditure cycle, such as we are**
28 **experiencing now, a jurisdiction's willingness to support large capital projects**
29 **with cash during the construction phase is an important aspect of our analysis.**
30 **This is especially true for ventures with big budgets and long lead times, such as**

1 baseload coal-fired or nuclear power plants and high-voltage transmission lines
2 that are susceptible to construction delays.⁹
3

4 **Q. Is there any specific evidence that OG&E’s planned transmission expenditures may**
5 **have an impact on OG&E’s credit ratings?**

6 A. Yes. On June 29, 2010, Fitch Ratings downgraded the Issuers Default Rating (“IDR”) of
7 OG&E from A+ to A. Fitch stated

8 The one-notch downgrade of OG&E is driven by downward-trending credit
9 metrics at the utility as it continues with a capital expenditure program that is
10 significantly higher than the historical norm. The cap-ex, which is being
11 primarily channeled into wind, transmission and smart grid investments, is
12 expected to remain elevated over the next several years based on known and
13 committed projects. While OG&E enjoys constructive regulatory treatment for
14 these investments and has minimal regulatory lag once these projects become
15 operational, there is expected to be pressure on credit metrics during the
16 construction period.¹⁰
17

18 **Q. Why are a utility’s credit ratings important to customers?**

19 A. Credit ratings determine the cost of borrowing funds for the utility, *i.e.*, the stronger the
20 rating, the lower the borrowing cost. Reduced borrowing costs reduce costs to customers.
21 Credit ratings also determine the ability to access capital markets and define a company’s
22 overall risk profile.
23

24 **Q. Are there other financial risks and challenges associated with the projects?**

25 A. Yes. OG&E has a number of additional capital expenditures that will compete with the
26 Sunnyside-Hugo and Sooner-Rose Hill projects for financing. OG&E is facing aging
27 utility infrastructure that will require investments higher than historical levels several
28 years into the future. Additionally, OG&E is investing in new Smart Grid technology
29 over the next three years and has additional obligations in renewable energy and
30 environmental initiatives. OG&E’s total projected base transmission, distribution,
31 generation and other capital expenditures through 2016, plus the expenditures for the

⁹ Shipman, Todd, *Assessing U.S. Utility Regulatory Environments in Standard & Poor’s Global Credit Portal: Ratings Direct* (March 11, 2010).

¹⁰ Fitch Ratings, “Fitch Downgrades OG&E’s IDR to ‘A’” (June 28, 2010).

1 projects, will be approximately \$3.5 billion. To put this in perspective, these total
2 projected expenditures are only slightly less than the Company's current total rate base.
3 The sheer volume of these capital expenditures means that a lot of capital projects will be
4 competing with the projects in question for funding priority.
5

6 **Q. Please describe the benefits to OG&E of receiving recovery through a rider for**
7 **these two projects.**

8 A. Recovery through the existing RTSA rider will give OG&E upfront regulatory certainty
9 and rate stability and also will improve cash flow. As discussed above, OG&E will face a
10 negative cash flow position as a result of its investment in all the large projects it is
11 constructing. As the credit rating agencies have recognized, certain regulatory
12 mechanisms—including CWIP and rider recovery—can strengthen a utility's cash flow.
13 For example, S&P stated “[a]llowance of a cash return on construction work-in-progress
14 or similar ratemaking methods historically were considered extraordinary measures for
15 use in unusual circumstances, but in today's environment of rising construction costs and
16 possible inflationary pressures, cash flow support could be crucial in maintaining credit
17 quality through the spending program.”¹¹

18 A more stable cash flow, in turn, bolsters a utility's credit ratings. In its report describing
19 the recent downgrade in OG&E's IDR, Fitch noted that “[o]ther favorable regulatory
20 mechanisms if implemented, such as cash recovery of capital costs during construction
21 work in progress, would be viewed as credit enhancing by Fitch.”¹² As noted by Fitch,
22 the CWIP and prompt cost recovery can prevent a possible credit downgrade by
23 providing more stable cash flow and decreasing financial risk. Because the requested
24 cost recovery reduces downward pressure on OG&E's credit ratings, OG&E would be
25 able to borrow money at a lower cost. Not having to finance AFUDC costs would also
26 help OG&E to minimize the total costs associated with financing the construction of the
27 Projects.

¹¹ Shipman, Todd, *Assessing U.S. Utility Regulatory Environments in Standard & Poor's Global Credit Portal: Ratings Direct* (March 11, 2010).

¹² Fitch Ratings, “Fitch Downgrades OG&E's IDR to ‘A’” (June 28, 2010).

1 Q. **Has OG&E identified the estimated revenue requirement for the full recovery of**
2 **these projects?**

3 A. Yes. OG&E's initial investment for these projects is projected to be approximately
4 \$195,266,520. Third party LSE's are expected to pay for 77.40% of the revenue
5 requirement for these projects. Therefore, the amount of transmission investment in
6 Oklahoma rate base will be reduced by \$151,136,286 to reflect the OG&E LSEs expected
7 cost responsibility for \$44,130,234, or 22.60% of the total investment. The revenue
8 requirement to Oklahoma customers will be based on the \$44 million investment.
9

10 O&M Benchmarking Study

11 Q. **You mentioned earlier in your testimony that you would discuss the O&M**
12 **benchmarking study conducted by PEG; can you please describe the study?**

13 A. Yes. The Company retained PEG to perform a study of the Company's recent generation
14 maintenance expense and a broader class of non-fuel O&M expenses. The study reported
15 results for the test year 2010, and for the period 2008 to 2010. PEG is a nationally
16 recognized firm that is a pioneer in utilization of economic benchmarking for the utility
17 industry.
18

19 Q. **Please describe PEG's study.**

20 A. PEG performed a statistical benchmark study in July 2011 based on 2010 cost levels. The
21 PEG study was based on 2010 generation O&M expenses for similarly situated vertically
22 integrated electric utilities, however, OG&E's expenses were adjusted to include the
23 \$5,905,566 increase in generation O&M expenses reflected in the *pro forma* adjustment
24 WP H 2-32. PEG's study utilizes cost indexing and econometric modeling to assess how
25 well a company is managing operations.
26

27 Q. **Briefly describe why the PEG Benchmarking Study is relevant in this proceeding?**

28 A. Results from the study show that OG&E effectively managed its operations through both
29 a high economic growth period (2008), an economic recession (2009), and a slow growth
30 post recession period (2010) while maintaining reliable service to customers. This study
31 also demonstrates that OG&E continues to be efficient as compared to other utilities,

1 even when considering the increased level of generation O&M currently being incurred.
2 Managing costs, while at the same time meeting future needs is critically important to the
3 Company, its customers and its regulators.
4

5 **Q. Please describe the general conclusions of the PEG Study?**

6 A. The results from the unit cost indexing demonstrate OG&E's generation maintenance
7 expenses are 10% below the peer group average even after adding \$5.9 million to the
8 2010 costs and about 22% for the period 2008 to 2010. OG&E's non-fuel O&M expenses
9 were found to be about 18% below the peer group average for 2010 and 23% below the
10 average from 2008 to 2010. During both periods OG&E's non-fuel O&M performance
11 was top quartile. In addition, PEG's econometric modeling demonstrates that after
12 increasing the PS O&M level by \$20 million, that level is 7% below the model's
13 projected expense level for the Company.
14

15 **Q. What conclusions can be drawn from the benchmark results that you present?**

16 A. A central question asked by our customers and our regulators is whether the Company is
17 performing efficiently. The benchmarking study results provide empirical evidence that
18 OG&E has demonstrated what the PEG report describes as "superior cost management of
19 its non-fuel O&M expenses." OG&E also continues to deliver above average cost
20 management of its generation maintenance costs even in the face of recent increased
21 plant maintenance expenditures.
22

23 Over/Under Fuel Recovery Interest Calculation

24 **Q. Is OG&E recommending a change in methodology for calculating interest on the
25 fuel recovery balance contained in the Fuel Clause Adjustment?**

26 A. Yes, the current interest calculation methodology used in Oklahoma is confusing,
27 complex and time-consuming. OG&E is proposing an alternative method that would be
28 much simpler to understand and easier to implement, yet would not materially change the
29 result.

1 Q. **Please explain the current method.**

2 A. The method currently requires that the Company calculate interest based on an
3 assumption that the amount either recoverable from or refundable to the customers will
4 remain in the fuel recovery balance for the remainder of the year. The recovery or refund
5 amount is then amortized equally over each month of the following calendar year. This
6 total interest amount, which includes all interest for future months until it is fully
7 amortized, is then immediately added to the balance of the fuel over/under recovery
8 amount. As a result, the fuel recovery account includes interest for future periods that
9 must be recorded as a deferred asset or liability on the Company's balance sheet, and then
10 charged to income or expense in the future until the balance is fully amortized for that
11 specific month.

12

13 Q. **Have you prepared an exhibit that reflects the current method?**

14 A. Yes. Exhibit DRR-2 shows the carrying charge calculation on the over/under recovery for
15 2010 using the current FCA tariff. Numerous accounting entries are required and
16 needless to say, this process is confusing and difficult to communicate to customers.

17

18 Q. **Please explain OG&E's proposed method.**

19 A. The proposed method would use the monthly average of the beginning and ending
20 balance of total fuel over/under recoveries (excluding interest) times the approved annual
21 interest rate divided by 12. The resulting interest would continue to be included with the
22 balance of fuel recoveries reported to the Commission in our monthly Governor's Report
23 filing. Any accumulated interest charges or credits would be included in the balance of
24 fuel over/under recoveries when calculating the new FCA.

25

26 Q. **What are the benefits of this change?**

27 A. The proposed method is easier to audit, is a more traditional approach to calculating
28 interest and is consistent with what is used by the Company in the Arkansas jurisdiction.
29 The proposed method is also more accurate since it uses a monthly average of the fuel
30 balance rather than just each month's over/under recovery amount.

1 Q. **Will this change require a modification to OG&E’s FCA tariff?**

2 A. Yes. The necessary FCA changes are included in the modified FCA tariff sponsored by
3 OG&E witness Gregory Tillman.
4

5 Elimination of OSSE Rider

6 Q. **What is OG&E recommending regarding the OSSE rider?**

7 A. OG&E is proposing that the SPP Energy Imbalance Services (“EIS”) market sales and
8 purchases be removed from the OSSE. After removal of EIS market activity, the
9 remaining off-system sales activity is minimal. OG&E is proposing to eliminate the
10 OSSE entirely and include off-system sales credits in the FCA.
11

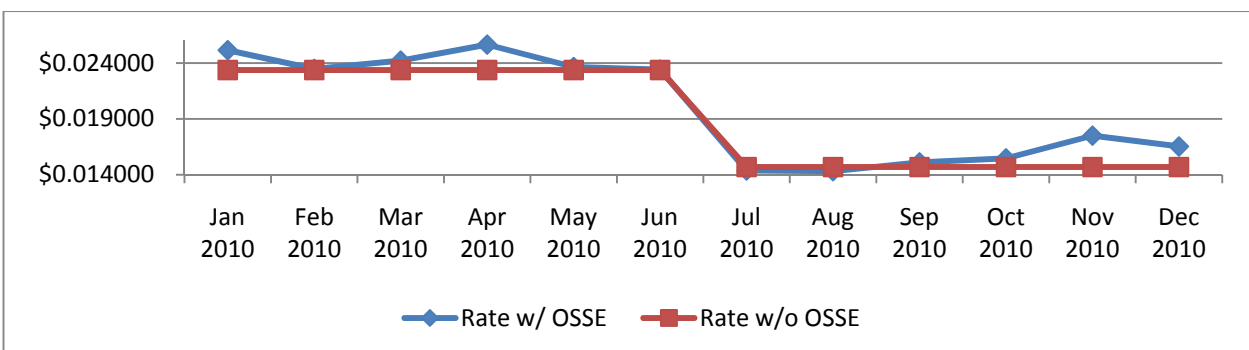
12 Q. **Why is OG&E proposing this change?**

13 A. The current OSSE treatment of EIS market transactions was agreed to in Cause No. PUD
14 200800086 and has become problematic to some of OG&E’s customers. It creates
15 volatility in the fuel charges applied to customer’s bills because of the significant amount
16 of dollars resulting from the EIS market purchases and sales. This is due to the difference
17 in the timing of cost recovery and revenue credits included in the OSSE. The OSSE is
18 adjusted monthly while the FCA is normally adjusted annually.
19

20 Q. **Have you prepared an exhibit that shows the volatility the current method has on
21 the fuel related billing determinants?**

22 A. Yes, please refer to Chart 3. The blue represents the 2010 actual OSSE with EIS sales
23 credits included, combined with the FCA factor as applied to customer’s bills. In contrast
24 the red line represents the 2010 FCA factor applied to customer’s bills.
25

Chart 3



1 Q. **What are the benefits of the proposed FCA/OSSE change?**

2 A. This change will help smooth out monthly customer bills by taking out the fuel related
3 volatility, which customers currently see resulting from the monthly changes in the
4 OSSE. Customers will see a more stable and consistent FCA. This change will match up
5 the timing of when the EIS market revenues are credited to customers with the ultimate
6 recovery of the related fuel costs and will result in smaller fuel over/under recoveries.

7

8 Q. **Does the proposed change above require a tariff modification?**

9 A. Yes. The necessary FCA tariff changes are contained in the modified FCA tariff
10 sponsored by OG&E witness Gregory Tillman.

11

12 Q. **Does this conclude your testimony?**

13 A. Yes.



Southwest Power Pool, Inc.
FINANCE COMMITTEE
Recommendation to the Board of Directors
October 26, 2010
2011 Administrative Fee

Organizational Roster

The following persons are members of the Finance Committee:

Harry Skilton, Chair	SPP Director
Larry Altenbaumer	SPP Director
Trudy Harper	Tenaska
Kelly Harrison	Westar
Sandra Bennett	AEP
Gary Voigt	Arkansas Electric

Background

Section 8.4 of the SPP Bylaws requires SPP to annually develop an assessment rate based on budgeted expenditures for the upcoming fiscal year and estimated billing determinants for that year.

Analysis

The 2011 SPP operating budget indicates a net revenue requirement ("NRR") for the year of \$78.6 and estimated billing determinants of 343,000,000 MWh. The rate is determined by dividing the NRR by the estimated billing determinants which results in a rate of 22.9¢/MWh. NRR is derived by adjusting SPP's gross cash outflows (exclusive of capital expenditures) by all non administrative fee revenue forecast to be earned in the year. The billing determinants are calculated by adjusting the current year's run rate by the growth factor published in the most recent EIA-411 report.

SPP's cash forecast indicates a rate of 21.0¢/MWh is sufficient to fully fund SPP's operations during the 2011 year, and increase to 25.5¢/MWh in 2012 and 28.0¢/MWh in 2013. Funding requirements in 2011 and beyond are based on numerous assumptions¹, should real time experience differ meaningfully from these assumptions, SPP's ability to operate at our current forecasted administrative fee may be jeopardized. SPP is able to maintain a rate below its expected costs to be incurred during 2010 due to its expenditures in prior years being below collected revenues.

Recommendation

The Finance Committee recommends the SPP Board of Directors establish an assessment rate and tariff administrative fee (schedule 1-A) of 21.0¢/MWh beginning on January 1, 2011.

Approved: Finance Committee **October 14, 2010**

Action Requested: Approve Recommendation

¹ load growth, membership stability, financing arrangements, implementation of consolidated balancing authority, development of future markets, etc.

Oklahoma Gas & Electric
Oklahoma Over/Under Carrying Charge Calculation Under Current FAC Tariff
For Month Ended November 2010

	Accounting Entries Required				
	Balance Sheet		Income Statement		
	Balance of Over Recovery	Balance of Deferred Debit	Monthly Amount Booked to Interest Expense		
November 2010 Over Recovery	\$ (12,056,230)				
Interest Rate	0.37%				
Total Interest	\$ (70,629)	\$ (70,629)	\$ 70,629	\$ -	
Dec 2010	\$ (3,717)	\$ (70,629)	\$ 66,912	\$ 3,717	
Jan 2011	\$ (3,717)	\$ (70,629)	\$ 63,195	\$ 3,717	
Feb 2011	\$ (3,717)	\$ (70,629)	\$ 59,478	\$ 3,717	
Mar 2011	\$ (3,717)	\$ (70,629)	\$ 55,761	\$ 3,717	
Apr 2011	\$ (3,717)	\$ (70,629)	\$ 52,044	\$ 3,717	
May 2011	\$ (3,717)	\$ (70,629)	\$ 48,327	\$ 3,717	
Jun 2011	\$ (3,717)	\$ (70,629)	\$ 44,610	\$ 3,717	
Jul 2011	\$ (3,717)	\$ (70,629)	\$ 40,893	\$ 3,717	
Aug 2011	\$ (3,717)	\$ (70,629)	\$ 37,176	\$ 3,717	
Sep 2011	\$ (3,717)	\$ (70,629)	\$ 33,459	\$ 3,717	
Oct 2011	\$ (3,717)	\$ (70,629)	\$ 29,742	\$ 3,717	
Nov 2011	\$ (3,717)	\$ (70,629)	\$ 26,025	\$ 3,717	
Dec 2011	\$ (3,717)	\$ (70,629)	\$ 22,308	\$ 3,717	
Jan 2012	\$ (3,431)	\$ (64,743)	\$ 18,877	\$ 3,431	
Feb 2012	\$ (3,145)	\$ (58,858)	\$ 15,732	\$ 3,145	
Mar 2012	\$ (2,859)	\$ (52,972)	\$ 12,873	\$ 2,859	
Apr 2012	\$ (2,574)	\$ (47,086)	\$ 10,299	\$ 2,574	
May 2012	\$ (2,288)	\$ (41,200)	\$ 8,011	\$ 2,288	
Jun 2012	\$ (2,002)	\$ (35,315)	\$ 6,009	\$ 2,002	
Jul 2012	\$ (1,716)	\$ (29,429)	\$ 4,293	\$ 1,716	
Aug 2012	\$ (1,430)	\$ (23,543)	\$ 2,863	\$ 1,430	
Sep 2012	\$ (1,144)	\$ (17,657)	\$ 1,719	\$ 1,144	
Oct 2012	\$ (858)	\$ (11,772)	\$ 861	\$ 858	
Nov 2012	\$ (572)	\$ (5,886)	\$ 289	\$ 572	
Dec 2012	\$ (289)	\$ -	\$ -	\$ 289	
	\$ (70,629)	\$ -	\$ -	\$ -	

Total interest for the November over recovery amount which is add to the fuel over recovery balance.

The deferred debit decreases as interest is recognized.

The amortization of the interest included in the over recovery amount begins (decreases by 1/12 each month).

By December 2012, all interest expense has been recognized on the income statement and all balance sheet accounts have cleared.