

**BEFORE THE CORPORATION COMMISSION
OF THE STATE OF OKLAHOMA**

**APPLICATION OF PUBLIC)
SERVICE COMPANY OF OKLAHOMA FOR)
A DETERMINATION THAT) CAUSE NO. PUD 2005-00516
ADDITIONAL ELECTRIC GENERATING)
CAPACITY WILL BE USED AND USEFUL)**

**APPLICATION OF PUBLIC)
SERVICE COMPANY OF OKLAHOMA)
FOR A DETERMINATION THAT)
ADDITIONAL BASELOAD ELECTRIC)
GENERATING CAPACITY WILL BE)
USED AND USEFUL) CAUSE NO. PUD 2006-00030**

**IN THE MATTER OF THE APPLICATION)
OF OKLAHOMA GAS AND ELECTRIC)
COMPANY FOR AN ORDER OF THE)
COMMISSION GRANTING PRE-APPROVAL)
TO CONSTRUCT RED ROCK) CAUSE NO. PUD 200700012
GENERATING FACILITY AND)
AUTHORIZING A RECOVERY RIDER)**

DIRECT TESTIMONY

OF

SCOTT NORWOOD

ON BEHALF OF

OKLAHOMA INDUSTRIAL ENERGY CONSUMERS (OIEC)

IN RESPONSE TO DIRECT TESTIMONY OF PSO

MAY 21, 2007

CAUSE NO. PUD 200600030

DIRECT TESTIMONY OF SCOTT NORWOOD

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1 **CAUSE NO. PUD 200600030**

2 **DIRECT TESTIMONY OF SCOTT NORWOOD**

3 **I. INTRODUCTION**

4

5

6 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

7 A. My name is Scott Norwood. My business address is P.O. Box 30197, Austin, Texas
8 78755.

9 **Q. WHAT IS YOUR OCCUPATION?**

10 A. I am an energy consultant specializing in the areas of electric utility regulation,
11 resource planning and energy procurement, and President of Norwood Energy
12 Consulting, L.L.C.

13 **Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**
14 **PROFESSIONAL EXPERIENCE.**

15 A. I have over 26 years of experience in the electric utility industry. After graduating
16 from the University of Texas in 1980 with a Bachelor of Science degree in electrical
17 engineering, I began my career as a power plant engineer for the City of Austin's
18 Electric Utility Department where I was responsible for electrical maintenance and
19 design projects for the City's three gas-fired power plants. In January 1984 I joined
20 the staff of the Public Utility Commission of Texas as Manager of Power Plant
21 Engineering, and in that capacity was responsible for addressing resource planning,
22 fuel and purchased power cost issues presented in regulatory filings before the
23 Commission. In 1986 I joined GDS Associates, Inc., a Marietta, Georgia-based

1 consulting firm that specializes in electric utility regulatory consulting and resource
2 planning. I was elected a Principal of GDS in 1990 and directed the firm's
3 Deregulation Services Department until January 2004, when I left GDS to form
4 Norwood Energy Consulting, LLC. The focus of my current consulting practice is
5 energy planning, procurement and regulation. A more detailed summary of my
6 background and experience is attached as Exhibit SN-1.

7 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?**

8 A. I am testifying on behalf of the Oklahoma Industrial Energy Consumers ("OIEC").

9 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE CORPORATION**
10 **COMMISSION OF OKLAHOMA?**

11 A. Yes. I have testified in a number of proceedings before the Corporation Commission,
12 including Public Service Company of Oklahoma's most recent base rate proceeding
13 and several other rate proceedings. In addition, I have testified as an expert on
14 regulatory and electric restructuring matters before the Arkansas House of
15 Representatives and before state regulatory commissions in Arkansas, Georgia, Iowa,
16 Illinois, Louisiana, Michigan, Missouri, New Jersey, Texas, Virginia, and Wisconsin.

17 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

18 A. The OIEC asked me to provide an opinion regarding PSO's request for a
19 determination that it needs up to 600 MW of baseload generating capacity by 2011,
20 and that its proposed 50% ownership interest in the Red Rock generating facility
21 represents the best available alternative for supplying this need at the lowest

1 reasonable cost to PSO's customers. In this regard, my testimony addresses the
2 reasonableness of PSO's resource planning studies which allegedly support the need
3 for the Red Rock project as well as PSO's evaluation of the project and other
4 alternatives.

5 **Q. HAVE YOU PREPARED ANY EXHIBITS TO SUPPORT YOUR**
6 **TESTIMONY?**

7 A. Yes. I have prepared 15 exhibits as support for my testimony.

8 **II. SUMMARY OF TESTIMONY**

9 **Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS**
10 **REGARDING PSO'S APPLICATION FOR APPROVAL OF THE RED ROCK**
11 **GENERATING FACILITY.**

12 A. My primary findings are as follows:

- 13 • PSO's plan to add up to 600 MW of new baseload generating capacity to its
14 system at some point during the current 10-year planning horizon generally
15 appears to be reasonable; if necessary, this capacity requirement could be
16 deferred until 2013 or 2014 if PSO continues its historical level of short-term
17 market capacity purchases;
- 18 • The current \$2.1 billion (\$2,360/kW) capital cost estimate for the Red Rock
19 facility is 55% higher than the reported costs of other new coal-fired
20 generating facilities that are scheduled for completion in the same time frame
21 as the Red Rock facility; the final Red Rock project cost is likely to be
22 significantly higher than the current cost estimate because it does not account
23 for a recently announced 8-month delay in the scheduled project in-service
24 date;
- 25 • The economic feasibility of the Red Rock project depends on the continued
26 participation of all three co-owners (OG&E, PSO and Oklahoma Municipal
27 Power Agency) in the project;

- 1 • OG&E's current integrated resource plan (IRP) indicates that the Company
2 will be able to supply its existing firm load obligations and minimum 12%
3 capacity reserve requirement without the Red Rock facility until 2014;
- 4 • PSO selected the Red Rock project through a competitive bidding process that
5 was initiated in late 2005; the bid evaluation process appears to have been
6 unduly biased in favor of the Red Rock proposal submitted by OG&E and
7 against a 30-year fixed price PPA proposal submitted by AES¹;
- 8 • PSO selected the Red Rock proposal over the AES PPA proposal despite the
9 fact that the forecasted costs of the Red Rock proposal were simply non-
10 binding estimates while the charges under the AES PPA were largely fixed;
- 11 • PSO added a \$447 million debt equivalence adjustment to the bid costs of the
12 AES PPA proposal; as discussed by OIEC witnesses Mark Garrett and
13 Randall Woolridge, this debt equivalence adjustment is excessive and
14 unjustified;
- 15 • PSO and OG&E agreed to modify the proposed design of the Red Rock
16 generating facility from a subcritical pulverized coal-fired unit to a ultra-
17 supercritical (USC) pulverized coal-fired unit; the Red Rock facility will be
18 the first USC coal-fired unit constructed in the United States in more than 60
19 years;
- 20 • PSO claims that it does not have recent data on similar USC units to support
21 its operating performance and cost assumptions for the Red Rock generating
22 facility;
- 23 • PSO estimates that converting the Red Rock facility to a USC design will
24 produce approximately \$6.7 million in cost benefits over the 40-year life of
25 the facility when compared to costs of a supercritical coal-fired generating
26 unit; the meager level of this forecasted benefit does not justify the increased
27 risk to PSO, OG&E and their customers due to converting the Red Rock
28 facility to a USC design;

29 My primary recommendations are as follows:

- 30 • I recommend that the Commission order PSO to immediately reopen its
31 bidding process to obtain new baseload bids with oversight and participation
32 of an Independent Evaluator retained by the Commission because PSO's
33 evaluation of baseload bids was seriously flawed and resulted in the selection
34 of the Red Rock project whose current cost estimate is much higher than costs
35 under the AES PPA bid that was rejected by PSO;

¹ The AES PPA bid was provided in PSO's highly sensitive response to OIEC Data Request 2-1.

- 1 • If the Commission decides that there is not adequate time to reopen bids and
2 that PSO should be allowed to go forward with its Red Rock proposal, I have
3 two alternative recommendations to help mitigate the adverse rate impacts of
4 the project on PSO's retail customers. First, I recommend that the
5 Commission cap PSO's recovery of capital costs for the Red Rock project and
6 associated transmission facilities at a total amount of \$945 million inclusive of
7 AFUDC. As discussed later in my testimony, this amount is consistent with
8 the level of Red Rock costs included in OG&E's original cost estimate for the
9 project. Second, I recommend that the Commission adopt minimum
10 performance standards for the Red Rock unit, including a minimum annual
11 equivalent availability factor standard of 85% and a maximum annual average
12 net heat rate standard of 9,000 BTU/kWh. These performance standards are
13 consistent with the level of performance assumed by OG&E and PSO in
14 justifying the conversion of Red Rock to a USC design.

15
16 **III. DESCRIPTION OF RED ROCK PROJECT**

17 **Q. PLEASE DESCRIBE THE PROPOSED RED ROCK GENERATING**
18 **FACILITY?**

19 A. The proposed Red Rock Generating Facility ("Red Rock") is a 950 MW (gross) coal-
20 fired generating unit located adjacent to OG&E's existing Sooner Generating Station,
21 near Red Rock, Oklahoma. The Red Rock project currently is scheduled to
22 commence commercial operations in February 2012. (See Exhibit SN-2.) The project
23 would be fueled by sub-bituminous coal delivered by rail from the Powder River
24 Basin in Wyoming. OG&E has been designated as the project manager for
25 construction and operations of the project.

26 **Q. WHAT IS THE ESTIMATED NET DEPENDABLE CAPABILITY RATING**
27 **OF THE RED ROCK PROJECT?**

1 A. The estimated annual net dependable capability of Red Rock is 892 MW. (See
2 Exhibit SN-3.) PSO's proposed 50% ownership share of the net dependable
3 capability of the Red Rock project would be approximately 446 MW.

4 **Q. WHO ARE THE OTHER OWNERS OF THE RED ROCK PROJECT?**

5 A. The other owners of the Red Rock project are OG&E and the Oklahoma Municipal
6 Power Agency (OMPA). The proposed ownership shares for the Red Rock project
7 are as follows:

8 **Red Rock Project Ownership Shares**

| | <u>MW</u> | <u>Share</u> |
|-------|-----------|--------------|
| PSO | 446 | 50% |
| OG&E | 375 | 42% |
| OMPA | <u>71</u> | <u>8%</u> |
| Total | 892 | 100% |

9

10 The rights and obligations of the co-owners of Red Rock are defined under the
11 Construction, Ownership and Operations Agreement for the project, which was
12 executed on December 14, 2006.

13 **Q. DOES THE PROPOSED CO-OWNERSHIP ARRANGEMENT FOR RED
14 ROCK HAVE ANY IMPACT ON THE FEASIBILITY OF THE PROJECT?**

15 A. Yes. The costs and feasibility of the proposed Red Rock project are inextricably tied
16 to the participation of all co-owners of the project. If any co-owner decides not to
17 participate in the project because of an adverse regulatory ruling, or other factors, the
18 Red Rock project would have to be reconfigured, and the economic feasibility of the
19 project could be jeopardized. For example, if the Commission were to determine that
20 OG&E does not need 375 MW of new baseload generating capacity in 2012, then the
21 Red Rock project would have to be redesigned and costs of the project would change.

1 **Q. WHAT IS THE ESTIMATED CONSTRUCTION COST OF THE RED ROCK**
2 **FACILITY?**

3 A. The original and current OG&E construction cost estimates for the Red Rock facility
4 are presented below. (See Exhibit SN-4 for source documents.) The original cost
5 estimate was prepared in early-February 2006, shortly before OG&E submitted its
6 Red Rock bid to PSO. The current cost estimate was prepared in September 2006,
7 approximately 2 months after PSO selected the OG&E's Red Rock bid. As shown
8 below, this revised cost estimate is more than \$200 million (11%) higher than the
9 original estimate that was provided with OG&E's original Red Rock bid.

10 **Red Rock Generating Project Construction Cost Estimates**

11 **(\$Millions)**

| | Original <u>2/3/06</u> | Current <u>9/29/06</u> |
|--------------------|---|---|
| Base Cost Estimate | \$1,614 | \$1,807 |
| AFUDC | \$184 | \$206 |
| Common Facilities | \$21 | \$21 |
| Transmission | <u>\$71</u> | <u>\$71</u> |
| Total | \$1,890 | \$2,105 |
| Total , \$/kW | \$2,119 | \$2,360 |

12
13 Sources are Jesse Langston's Exhibit JBL-9 and OG&E's
14 response to OIEC 3-5.

15 **Q. HOW DOES THE CURRENT COST ESTIMATE FOR THE RED ROCK**
16 **PROJECT COMPARE TO COSTS FOR OTHER RECENTLY ANNOUNCED**
17 **COAL-FIRED PLANTS?**

1 A. As shown below, the current cost estimate for the Red Rock project is approximately
 2 55% higher than the average cost of other coal-fired power plants that are scheduled
 3 to be completed in the same general time frame:
 4

5 **Comparison of New Coal-fired Power Plant Costs, \$Millions**

| <u>Developer</u> | <u>Location</u> | <u>Capacity</u> | <u>In-Service</u> | <u>Investment</u> | <u>\$/kW</u> |
|------------------------|-----------------|-----------------|-------------------|-------------------|----------------|
| Tucson Electric | Arizona | 400 | 2009 | \$650 | \$1,625 |
| Seminole ECI | Florida | 750 | 2012 | \$1,200 | \$1,600 |
| Jacksonville EA | Florida | 800 | 2012 | \$1,400 | \$1,750 |
| Southern Company | Florida | 787 | 2012 | \$800 | \$1,017 |
| Peabody Energy | Illinois | 1,500 | 2011 | \$2,000 | \$1,333 |
| LS Power | Iowa | 750 | 2011 | \$1,300 | \$1,733 |
| Sunflower EPC | Kansas | 2,100 | 2011-2013 | \$2,500 | \$1,190 |
| LG&E Powergen | Kentucky | 750 | 2010 | \$1,200 | \$1,600 |
| Great Plains Energy | Missouri | 850 | 2011 | \$1,300 | \$1,529 |
| Sempra | Nevada | 1,450 | 2011 | \$2,000 | \$1,379 |
| Sierra Pacific | Nevada | 1,500 | 2011 | \$3,000 | \$2,000 |
| Omaha PPD | Nebraska | 660 | 2009 | \$850 | \$1,288 |
| Sithe Global Power | New Mexico | 1,500 | 2010 | \$2,500 | \$1,667 |
| NRG | New York | 630 | 2012 | \$1,500 | \$2,381 |
| American Municipal Pwr | Ohio | 1,000 | 2012 | \$1,200 | \$1,200 |
| Western Farmers ECI | Oklahoma | 750 | 2011 | \$1,200 | \$1,600 |
| Santee Cooper | South Carolina | 600 | 2014 | \$984 | \$1,640 |
| Otter Tail Power | South Dakota | 600 | 2011 | \$1,000 | \$1,667 |
| TXU | Texas | 6,400 | 2010 | \$10,000 | \$1,563 |
| City Public Service | Texas | 750 | 2010 | \$1,000 | \$1,333 |
| LS Power | Texas | 800 | 2011 | \$1,000 | \$1,250 |
| TXU | Texas | 1,720 | 2009 | \$2,000 | <u>\$1,163</u> |
| | | | | Average: | \$1,523 |
| OG&E/PSO (Red Rock) | Oklahoma | 892 | 2011 | \$2,105 | \$2,360 |
| | | | | | 55.0% |

Source: PSO's Response to AG 7-25b.

6

7 **Q. WHAT DETERMINATIONS DOES PSO SEEK FROM THE**
 8 **COMMISSION WITH REGARD TO ITS RED ROCK PROPOSAL?**

9 A. As described in PSO witness Solomon's supplemental direct testimony, the
 10 Company is seeking the following three determinations from the Commission:

11 1) that PSO's plan to acquire up to 600 MW of baseload generating
 12 resources in 2011 is prudent and reasonable;
 13

1 2) that PSO's 50% ownership share of the Red Rock project will be used
2 and useful; and

3
4 3) that PSO's competitive bidding process used in connection with its
5 decision to own the Red Rock project was consistent with the
6 Commission's competitive bidding rules and was prudent, unbiased and
7 resulted in the lowest reasonable cost alternative being bid and selected.
8

9 **Q. ARE PSO OR OG&E WILLING TO CAP THEIR RECOVERY OF RED
10 ROCK CAPITAL AND OPERATING COSTS AT LEVELS THAT ARE
11 CONSISTENT WITH COMPETING BIDS THAT WERE REJECTED BY
12 PSO?**

13 A. No. (See Exhibit SN-5.)

14 **Q. ARE PSO OR OG&E WILLING TO GUARANTEE THE 2011 IN SERVICE
15 DATE FOR THE RED ROCK PROJECT AS WAS REQUIRED FOR OTHER
16 BIDS THAT WERE REJECTED BY PSO?**

17 A. No. (See Exhibit SN-6.)

18 **Q. ARE PSO OR OG&E WILLING TO AGREE TO PERFORMANCE
19 STANDARDS FOR RED ROCK THAT ARE CONSISTENT WITH THE
20 EFFICIENCY AND AVAILABILITY LEVELS ASSUMED BY PSO IN
21 JUSTIFYING ITS SELECTION OF RED ROCK?**

22 A. No. (See Exhibit SN-7.)

23 **Q. WOULD IT BE REASONABLE FOR THE COMMISSION TO REQUIRE PSO
24 AND OG&E TO GUARANTEE COSTS AND PERFORMANCE OF THE RED
25 ROCK FACILITY IF IT IS CONSTRUCTED?**

26 A. Yes. OG&E's original Red Rock project bid was selected by PSO over a competing
27 PPA proposal from AES that included both price and performance guarantees. As

1 discussed later in my testimony, the AES PPA offered significantly lower costs and
2 more coal-fired capacity (554 MW) to PSO than will be provided under OG&E's
3 original Red Rock bid. Moreover, after selecting OG&E's original Red Rock bid,
4 PSO and OG&E agreed to convert the Red Rock project to a USC design based
5 largely on the assumption that the plant would have a significantly better heat rate
6 (i.e., efficiency) performance than OG&E's original Red Rock proposal. As a result
7 of this modification to USC design, and other factors, the Red Rock project cost
8 estimate was significantly increased in September 2006, only two months *after* PSO
9 selected OG&E's Red Rock proposal as the winning bid. The revised Red Rock
10 project cost estimate already is far higher than costs under the AES PPA proposal and
11 is likely to go higher. In contrast, charges under the AES PPA were largely fixed and
12 were subject to discounts in the event that the availability performance of the AES
13 project fell below a certain level. Given these facts, and the fact that PSO and OG&E
14 justified the increased capital costs and risks of Red Rock's conversion to an USC
15 design based on an assumed high level of performance, it would be unreasonable for
16 PSO and OG&E not to guarantee the cost and performance of the Red Rock
17 generating facility if the project is allowed to go forward.

18 **IV. NEED FOR RED ROCK CAPACITY**

19 **Q. WHAT INFORMATION HAS PSO PROVIDED TO DEMONSTRATE THE**
20 **NEED FOR THE PROPOSED RED ROCK PROJECT?**

21 A. PSO witness Scott Weaver has presented the results of PSO's Spring 2005 IRP
22 analysis in his supplemental testimony as support for the Company's need for up to

1 600 MW of baseload generating capacity in 2011. The determination of this capacity
2 need primarily is a function of the installed capacity and operating characteristics of
3 PSO's existing generating resources, PSO's planning reserve criterion, and the level
4 of forecasted peak demand, among other factors.

5 **Q. WHAT IS PSO'S PLANNING RESERVE CRITERION?**

6 A. PSO plans its system in order to maintain a 12% minimum capacity margin,
7 consistent with SPP guidelines. Capacity margin equals the available reserve
8 capacity divided by installed capacity of the system.

9 **Q. WHAT LEVEL OF NEW GENERATING CAPACITY DOES PSO'S SPRING**
10 **2005 IRP INDICATE WILL BE NEEDED BY 2011?**

11 A. The results of PSO's Capability, Demand and Reserves (CDR) Forecast, as presented
12 in Exhibit SCW-17S of Mr. Weaver's Supplemental Testimony, are summarized
13 below. As shown, PSO's Spring 2005 IRP indicated that, after accounting for the
14 new capacity supplied from the Company's proposed combustion turbine peaking
15 units, and assuming no additional short term market capacity purchases are made
16 from the Southwest Power Pool (SPP) and AEP East regions, PSO would require
17 approximately 300 MW of new generating capacity by 2011 in order to meet its 12%
18 minimum capacity reserve target.

19
20
21
22
23

1

PSO’s System Capability, Demand and Reserves Forecast

| | <u>2009</u> | <u>2010</u> | <u>2011</u> | <u>2012</u> | <u>2013</u> | <u>2014</u> |
|--------------------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Net Plant Capability | 4,165 | 4,165 | 4,165 | 4,165 | 4,165 | 4,165 |
| New CTs | 336 | 336 | 336 | 336 | 336 | 336 |
| Market Purchases | <u>311</u> | <u>117</u> | <u>58</u> | <u>58</u> | <u>58</u> | <u>58</u> |
| Total Capability | 4,812 | 4,618 | 4,559 | 4,559 | 4,559 | 4,559 |
| Adjusted Peak Demand | 4,210 | 4,268 | 4,324 | 4,382 | 4,431 | 4,479 |
| | | 1.4% | 1.3% | 1.3% | 1.1% | 1.1% |
| Reserve Capacity | 602 | 350 | 235 | 177 | 128 | 80 |
| Capacity Margin | 12.5% | 7.6% | 5.2% | 3.9% | 2.8% | 1.8% |
| Reserves over 12% Margin | 25 | -204 | -312 | -370 | -419 | -467 |

Source: PSO witness Weaver's supplemental direct testimony, Exhibit SCW-17S. System capability excludes proposed Red Rock project.

2

3

4 **Q. IS PSO’S PEAK DEMAND FORECAST REASONABLE?**

5 A. PSO’s peak demand forecast generally appears to be reasonable. The forecasted
6 demand growth rates over the 2009-2013 period fall in the range of 1.1% to 1.4% per
7 year, which is slightly lower than peak demand growth rates that have been
8 experienced on PSO’s system during the last several years.

9 **Q. IS PSO’S SYSTEM GENERATING CAPABILITY FORECAST
10 REASONABLE?**

11 A. Based on the relatively high percentage of gas-fired generating resources on PSO’s
12 system, and the current level of natural gas prices, PSO’s plan to add coal-fired
13 baseload generating capacity to its system at some point during the current 10-year
14 planning horizon generally appears to be reasonable. However, PSO’s forecast that
15 its system will require up to 600 MW of coal-fired baseload generating capacity by
16 2011 does not appear to be justified. This forecast assumes that PSO’s short-term
17 market capacity purchases will be significantly lower after 2007. For example, the

1 Company's CDR forecast assumes that market capacity purchases will drop from 492
2 MW in 2007 to only 58 MW in 2011. This assumption is unreasonable.

3 **Q. WHY WAS IT UNREASONABLE FOR PSO TO ASSUME THAT MARKET**
4 **PURCHASES COULD NOT CONTINUE TO SUPPLY A SIGNIFICANT**
5 **PORTION OF THE COMPANY'S SYSTEM CAPACITY NEEDS?**

6 A. There is forecasted to be approximately 3,000 MW of excess capacity in the SPP
7 region during the 2010-2011 period. (See Weaver's Exhibit SCW-8.) This
8 forecasted availability of market capacity for purchase provides PSO with the
9 flexibility to meet its system capacity and reserve requirements in the event that the
10 Red Rock project is further delayed for any reason. Market capacity purchases also
11 would increase the diversity of PSO's energy resources and therefore serve as a hedge
12 against unanticipated increases in natural gas or coal-fired energy prices. In fact,
13 OG&E has indicated it plans to rely upon short-term market capacity purchases in
14 this manner to supplement its system capacity needs until the Red Rock project is
15 completed.

16 **Q. DOES OG&E REQUIRE ADDITIONAL BASELOAD GENERATING**
17 **CAPACITY ON ITS SYSTEM BY 2011 AS WOULD BE SUPPLIED FROM**
18 **THE RED ROCK PROJECT?**

19 A. No. OG&E's peak demand forecast that was used to justify the construction of the
20 Red Rock facility assumes that a number of OG&E wholesale contracts that are
21 scheduled to expire before 2011 would be renewed. The combined load of these
22 wholesale contracts is approximately 300 MW. (See Exhibit SN-8.) However, as
23 shown below, if these contracts are removed from OG&E's long-term firm peak

1 demand forecast, the Company will have adequate capacity to meet its system peak
 2 demand and reserves requirement until 2014 without adding the Red Rock unit.

3 **OG&E's System Capability, Demand and Reserves Forecast**

| | <u>2010</u> | <u>2011</u> | <u>2012</u> | <u>2013</u> | <u>2014</u> | <u>2015</u> |
|--------------------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Total System Capability | 7,090 | 7,090 | 7,090 | 7,090 | 7,090 | 7,090 |
| Total Peak Demand | 6,036 | 6,116 | 6,212 | 6,299 | 6,396 | 6,538 |
| Demand Side Programs | <u>127</u> | <u>127</u> | <u>127</u> | <u>127</u> | <u>127</u> | <u>127</u> |
| Adjusted Peak Demand | 5,909 | 5,989 | 6,085 | 6,172 | 6,269 | 6,411 |
| Reserve Capacity | 1,181 | 1,101 | 1,005 | 918 | 821 | 679 |
| Capacity Margin | 16.7% | 15.5% | 14.2% | 12.9% | 11.6% | 9.6% |
| Reserves over 12% Margin | 330.2 | 250.2 | 154.2 | 67.2 | -29.8 | -171.8 |

Source: OG&E's supplemental response to AG's RFI 2-46 and Table II-8 from OG&E's IRP. System peak demand excludes expiring wholesale contracts. System capability excludes proposed Red Rock capacity.

4

5 **Q. WOULD IT BE APPROPRIATE TO APPROVE THE RED ROCK**
 6 **GENERATING FACILITY BASED IN PART ON SPECULATION THAT**
 7 **OG&E'S EXISTING WHOLESALE CONTRACTS WILL BE RENEWED?**

8 A. No. If the wholesale contracts at issue are not renewed, then the need for the Red
 9 Rock project will be deferred for several years. Given the high fixed cost of the Red
 10 Rock facility, the need for this unit should not be so highly dependent on such a
 11 speculative assumption.

12 **Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS**
 13 **REGARDING PSO'S CLAIMED NEED FOR 446 MW OF COAL-FIRED**
 14 **GENERATING CAPACITY FROM THE RED ROCK PROJECT IN 2011?**

15 A. It appears that PSO may need approximately 300 to 500 MW of additional generating
 16 capacity during the 2011-2014 time frame in order to meet its minimum 12% capacity
 17 margin reserve requirement. In contrast, OG&E will not require additional
 18 generating capacity until 2014 unless several wholesale contracts that are scheduled

1 to expire are renewed. Under current market conditions, it generally appears that
2 coal-fired baseload generation would be a competitive option for supplying PSO's
3 capacity requirements during this period. However, the costs of the Red Rock project
4 are very high, and there is forecasted to be sufficient excess capacity in the SPP
5 region to allow PSO's to defer its next baseload capacity addition until 2013 or 2014,
6 if necessary, to allow time for the Company to seek new bids for more cost-effective
7 resources.

8 **V. PSO'S EVALUATION OF ALTERNATIVES**

9 **Q. WHAT PROCESS WAS USED BY PSO TO EVALUATE ALTERNATIVES**
10 **TO SUPPLY ITS BASELOAD CAPACITY NEED FOR 2011?**

11 A. PSO initially identified and evaluated alternatives to supply its capacity needs for
12 2011 through its IRP process, as described in the supplemental direct testimony of
13 PSO witness Scott Weaver. After determining that a baseload generating resource of
14 up to 600 MW would be the optimal resource addition for serving its summer 2011
15 capacity needs, PSO decided to solicit competitive bids to supply this need through a
16 request for proposals (RFP) for baseload generation. The Company issued its
17 baseload RFP in December of 2005. The RFP established the criteria that PSO would
18 use to evaluate proposals and set a deadline of February 16, 2006 for final bids.

19 **Q. WHY DID PSO ISSUE AN RFP FOR BASELOAD GENERATION?**

20 A. During March of 2005, nine months before PSO issued its baseload RFP, the
21 Commission initiated a rulemaking to develop rules to require competitive bidding

1 for new generating resources. PSO participated in this rulemaking and filed
2 comments that were generally supportive of using competitive bidding for new
3 resources “to ensure that resource costs are held to the lowest reasonable cost.” (See
4 Exhibit SN-9.) PSO was aware of the proposed bidding rule requirements and that
5 the rules would be in effect during the time frame that it was evaluating its new
6 baseload generating requirements. In fact, PSO admits that it structured its RFP and
7 bid evaluation process to conform with the anticipated requirements of the new
8 bidding rules, which ultimately were adopted in January 2006, only a month after
9 PSO issued its RFP.

10 **Q. WHAT WERE THE MAJOR CRITERIA ESTABLISHED BY PSO IN ITS**
11 **BASELOAD RFP?**

12 A. Section 3.1 of the RFP states that PSO was seeking proposals for up to 600 MW of
13 firm capacity and energy with a commercial operation date of June 1, 2011, in the
14 form of Power Purchase Agreements (PPAs) or the acquisition of existing generating
15 facilities. PSO’s RFP further stated that the Company was interested in proposals that
16 minimized risk and costs to PSO and its customers, and encouraged bidders to
17 provide proposals that reflected what they believed to be their best pricing proposal.
18 With regard to asset purchase proposals, section 3.4 of the RFP specifies that
19 proposals should be based on “existing generating assets that have a proven operating
20 history,” and that such proposals shall be “priced at a fixed dollar amount inclusive of
21 all monetary consideration for the generating assets.”

1 **Q. HOW MANY PROPOSALS DID PSO RECEIVE IN RESPONSE TO ITS**
2 **BASELOAD RFP?**

3 A. PSO received six bids in response to its baseload RFP. Three of the bids were AEP
4 self-build proposals based on three different coal-fired generating technologies,
5 including a circulating fluidized bed facility, an integrated coal gasification
6 combined-cycle facility, and an ultra-supercritical pulverized coal-fired generating
7 facility. PSO rejected one of the other three bids, a 600 MW asset sale proposal
8 involving an existing gas-fired combined cycle facility, because the bidder did not
9 meet the \$500 million minimum tangible net worth threshold requirement. The other
10 two bids were provided by AES and OG&E. The AES bid offered both a PPS with
11 an asset ownership option, as well as a conventional 30-year PPA alternative based on
12 a supercritical pulverized coal-fired generating facility. PSO ultimately concluded
13 that the AES PPA/asset sale option involved too much uncertainty and therefore
14 rejected this proposal and focused its analysis on AES's alternative PPA proposal.
15 The OG&E proposal offered PSO a 50% ownership in the proposed Red Rock
16 generating facility, which was proposed as a subcritical pulverized coal-fired facility.
17 After PSO selected OG&E's Red Rock bid, OG&E and PSO decided to modify the
18 Red Rock project to incorporate a USC design and to include a third co-owner
19 (OMPA).

20 **Q. HOW DID PSO EVALUATE THE FIVE PROPOSALS WHICH IT JUDGED**
21 **TO BE IN SUBSTANTIAL CONFORMANCE WITH ITS RFP**
22 **REQUIREMENTS?**

1 A. PSO conducted both quantitative cost/benefit analyses and qualitative analyses of
2 non-price characteristics of the five remaining proposals. In its evaluation of the
3 proposals, PSO assigned a 60% weighting factor to the cost/benefit rankings of each
4 proposal and a 40% weighting factor to the non-price factor rankings.

5 **Q. WHAT FACTORS WERE CONSIDERED BY PSO IN ITS EVALUATION OF**
6 **NON-PRICE CHARACTERISTICS OF EACH PROPOSAL?**

7 A. PSO's non-price evaluation focused on five broad categories including: 1) flexibility,
8 2) development feasibility, 3) operational viability, 4) quality of output and 5) model
9 contracts. The results of this non-price evaluation are summarized in PSO witness
10 Fate's Exhibit SLF-3S. As demonstrated by this exhibit, all of the proposals with the
11 exception of AES's PPA proposal (Bid B5) ranked relatively high on the non-price
12 evaluation.

13 **Q. WHY WAS THE AES PROPOSAL RANKED SIGNIFICANTLY LOWER**
14 **THAN OTHER PROPOSALS ON NON-PRICE FACTORS?**

15 A. The AES proposal ranked significantly lower than other proposals in the "quality of
16 output" and "model contracts" non-price categories. For example, within the quality
17 of output category, the AES PPA received zero points out of a possible 55 points for
18 scheduling and dispatch characteristics, and 4 points out of a possible 45 points for
19 operating profile characteristics. The AES PPA also received 0 points out of a
20 possible 50 points for "contract exceptions" in the model contracts category. (See
21 Exhibit SLF-3S.)

1 **Q. WERE THE LOW NON-PRICE RANKINGS OF THE AES PROPOSAL**
2 **CONSISTENT WITH PSO'S RANKINGS OF OTHER PROPOSALS?**

3 A. No. For example, on the scheduling and dispatch issue, AES received the lowest
4 possible ranking even though the AES proposal indicated that the Company was
5 willing to negotiate terms that were mutually agreeable to each party. Similarly,
6 while AES received a score of 0 for contract exceptions, the OG&E proposal received
7 a relatively high score of 26 even though the COO agreement that governs co-owners
8 rights and obligations for the Red Rock project was substantially changed from the
9 original contract terms proposed by PSO and was not finalized until 10 months after
10 the OG&E proposal was selected. These inconsistencies in the non-price rankings
11 indicate a bias in the evaluation against the AES proposal and in favor of the OG&E
12 and self-build bids.

13 **Q. HOW DID PSO EVALUATE THE ECONOMIC COSTS AND BENEFITS OF**
14 **EACH PROPOSAL?**

15 A. PSO conducted production cost modeling studies to quantify the effects of each
16 proposal on the cumulative present worth of the total production costs of its system
17 with and without each of the five proposals. The Company conducted scenarios that
18 considered a range of natural gas prices as well as runs that evaluated each proposal
19 based on 450 MW of delivery (approximately PSO's proposed share of Red Rock
20 capacity), rather than the actual bid capacity. For each of the cases evaluated, PSO
21 assigned a debt equivalence adjustment to the AES PPA proposal to reflect the
22 Company's assessment of the cost of this proposal on its capital structure.

1 **Q. WAS PSO'S ECONOMIC ANALYSIS OF THE BASELOAD BIDS**
2 **REASONABLE?**

3 A. No. PSO's baseload bid evaluation process was seriously flawed and unduly biased
4 in favor of the Red Rock project and the AEP self-build proposals, and biased against
5 the AES PPA proposal.

6 **Q. WHAT WERE THE MAJOR FLAWS IN PSO'S BASELOAD BID**
7 **EVALUATION PROCESS?**

8 A. The most significant flaw in PSO's evaluation of baseload bids was that the Company
9 did not account for the fact that the capital and O&M charges under the AES PPA
10 proposal were largely fixed prices whereas all capital and operating costs provided in
11 AEP self-build proposals and OG&E's Red Rock proposal are simply non-binding
12 estimates that have already increased and are likely to further increase in the future.
13 For example, PSO's economic analysis of the Red Rock proposal assumed that the
14 capital cost of the project would be approximately \$1.6 billion, however less than 7
15 months after bids were evaluated the construction cost estimate for the project was
16 raised to \$1.8 billion, excluding interest and other related project costs. (See Exhibit
17 SN-4.) Furthermore, PSO's analysis of baseload bids did not account for other
18 significant risks of the Red Rock project that could greatly diminish forecasted
19 benefits of the project, such as the effect of co-ownership dispatch rights and the
20 largely unproven USC design that ultimately was selected for the project.

21 In addition, PSO ignored the fact that Red Rock did not meet many of the
22 major bid evaluation criteria identified in its baseload RFP. For example, Section 3.1

1 of the RFP states that PSO was seeking proposals for up to 600 MW of firm capacity
2 and energy with a commercial operation date of June 1, 2011, in the form of Power
3 Purchase Agreements (PPAs) or the acquisition of existing generating facilities.
4 PSO's RFP further stated that the Company was interested in proposals that
5 minimized risk and costs to PSO and its customers, and encouraged bidders to
6 provide proposals that reflected what they believed to be their best pricing proposal.
7 With regard to asset purchase proposals, section 3.4 of the RFP specifies that
8 proposals should be based on "existing generating assets that have a proven operating
9 history," and that such proposals shall be "priced at a fixed dollar amount inclusive of
10 all monetary consideration for the generating assets." OG&E's Red Rock proposal
11 failed to meet each of the above criteria.

12 **Q. WERE THE MODIFICATIONS TO THE RED ROCK PROJECT DESIGN,**
13 **OWNERSHIP AND COSTS EVALUATED BY PSO BEFORE IT SELECTED**
14 **OG&E'S PROPOSAL AS THE WINNING BID?**

15 A. No. PSO only evaluated the price and non-price factors of OG&E's initial proposal
16 for the Red Rock project which was based on a subcritical pulverized coal-fired unit
17 design. Only after OG&E's Red Rock proposal was selected as the winning bid in
18 July 2006, did PSO and OG&E evaluate costs of the original Red Rock bid in
19 comparison to costs of the currently proposed USC Red Rock project. These
20 additional production cost studies indicated that the modified USC Red Rock project
21 would lower the total production revenue requirements of the PSO system by
22 approximately \$6.7 million over the 40-year study period when compared to the
23 original subcritical Red Rock design proposed by OG&E. (See Exhibit SN-10.)

1 This forecasted cost savings is less than 0.05% (five one-hundredths of one percent)
2 of total estimated production costs of the PSO system which is extremely small when
3 compared to the level of uncertainty inherent in the forecasting process.

4 **Q. WERE THERE OTHER PROBLEMS WITH PSO'S EVALUATION OF**
5 **BASELOAD BIDS?**

6 A. Yes. For example, PSO assigned a \$447 million debt equivalence adjustment to the
7 AES PPA proposal to reflect the Company's assessment of the cost of this proposal
8 on its capital structure. (See Exhibit SN-11.) However, such adjustments have not
9 previously been approved by the Oklahoma Corporation Commission, and in the
10 handful of states where they have been approved, regulators have typically applied a
11 risk factor in the range of 30% to 50% to reflect the risk of recovery of PPA fixed
12 charges, in deciding the necessary size of the debt equivalence adjustment for such
13 contracts. (See Exhibit SN-12.) PSO applied a 100% risk factor in calculating its
14 proposed debt equivalence adjustment of \$447 million for the AES PPA proposal.
15 OIEC witnesses Randall Woolridge and Mark Garrett address specific technical
16 problems with PSO's proposed debt equivalence adjustment and explain why it is
17 unreasonable to apply such a penalty to the AES PPA proposal, which except for this
18 adjustment and other flaws in PSO's bid evaluation process, was by far the lowest
19 cost bid received by PSO in response to its baseload RFP.

20 **Q. WOULD OG&E'S RED ROCK PROPOSAL BE THE HIGHEST RANKING**
21 **PROPOSAL IF THESE FLAWS IN PSO'S BID EVALUATION PROCESS**
22 **WERE CORRECTED?**

1 A. No. For example, if PSO’s economic analysis of the baseload proposals were
 2 updated simply to reflect the current construction cost estimate of the Red Rock
 3 project, the AEP PPA would have been the least cost bid by nearly \$139 million on a
 4 cumulative present worth basis. In fact, as shown below, the AES PPA proposal
 5 would provide an economic advantage of more than \$362 million to PSO when
 6 compared to the Red Rock proposal simply by applying a more reasonable 50% risk
 7 factor in determining PSO’s debt equivalence adjustment, and updating the analysis
 8 to reflect the increase in the current construction cost estimate for the Red Rock
 9 project that was not attributable to the change to USC design.

10
 11 **Updated Cost Benefit of AES PPA Proposal**

| | <u>AES PPA</u> | <u>Red Rock</u> | <u>AES PPA Advantage</u> |
|--------------------------------|----------------|------------------|------------------------------|
| Debt Equivalence at 50% | -\$223,500 | \$0 | \$223,500 |
| *Updated Red Rock Capital Cost | <u>\$0</u> | <u>\$138,657</u> | <u>\$138,657</u> |
| | -\$223,500 | \$138,657 | \$362,157 |

12 *Represents estimated increase not attributable to USC design.

13 **Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS**
 14 **REGARDING PSO’S EVALUATION OF BASELOAD PROPOSALS?**

15 A. PSO’s evaluation of baseload alternatives was flawed and unduly biased in favor of
 16 OG&E’s Red Rock proposal and unduly biased against AES’s PPA proposal. The
 17 AES PPA bid is far superior to the Red Rock proposal in terms of the level and
 18 certainty of power costs and the quantity of baseload capacity and energy delivered in
 19 2011. As discussed by OIEC witnesses Woolridge and Garrett, PSO’s proposed

1 A. Industry reports indicate that construction costs for new coal-fired generating units
2 have escalated significantly over the last several years. The current cost estimate of
3 the Red Rock project was developed in September 2006, and at that time the project
4 completion date was assumed to be June of 2011. Since that estimate was developed,
5 the Red Rock project completion date has been delayed by approximately 8 months to
6 February 2012. This delay will contribute to increased escalation and interest costs
7 for the project. A one year delay in the completion date of the project could increase
8 construction interest costs by \$100 million or more. There is significant risk for
9 additional delays and cost increases due to the complexity and magnitude of the Red
10 Rock project and the high demand for power plant engineering and construction
11 services. Moreover, because the Red Rock project will be the first USC coal-fired
12 generating unit constructed in the United States since 1949, it is quite possible that
13 unanticipated cost increases could occur simply due to the lack of available recent
14 construction cost information from other similar USC projects. Given these factors, it
15 is reasonable to assume that the final construction cost of the Red Rock facility will
16 be significantly higher than the current \$2.1 billion cost estimate. As noted earlier in
17 my testimony, PSO and OG&E have indicated that they will not agree to cap
18 recovery of the capital or operating costs of the Red Rock project at the level
19 reflected in OG&E's bid that was relied upon by PSO to select the Red Rock project
20 over the AES PPA bid which offered largely fixed costs.

21 **Q. DID PSO ACCOUNT FOR THIS COST RISK IN ITS EVALUATION OF THE**
22 **RED ROCK PROPOSAL?**

1 A. No. PSO's acceptance of OG&E's non-binding cost estimate for the Red Rock
2 facility is in conflict with the requirement in section 3.4 of its baseload RFP that asset
3 ownership proposals shall be "priced at a fixed dollar amount inclusive of all
4 monetary consideration for the generating assets." Moreover, PSO's decision to
5 select OG&E's Red Rock proposal was based on an economic evaluation that
6 assumed the plant construction cost was approximately \$200 million lower (excluding
7 interest) than the current outdated cost estimate. Because the capacity charges under
8 the AES proposal are fixed, PSO's failure to evaluate scenarios that assumed a higher
9 construction cost for the Red Rock facility constitutes a fatal flaw in the Company's
10 bid evaluation process.

11 **Q. WHAT IS THE RISK THAT THE PERFORMANCE OF THE RED ROCK**
12 **FACILITY WILL NOT BE AS GOOD AS ASSUMED BY PSO IN**
13 **JUSTIFYING THE PROJECT?**

14 A. OG&E's and PSO's evaluation in support of modifying the original subcritical Red
15 Rock proposal to a USC design forecasted that Red Rock would operate at an average
16 equivalent availability above 85% and an average heat rate below 9,000 BTU/kWh.
17 (See Exhibit SN-13.) However, the Companies admit that there is no available
18 information from other similar USC units to support these Red Rock performance
19 assumptions. (See Exhibit SN-14.)

20 **Q. DID PSO ACCOUNT FOR THIS RISK IN ITS EVALUATION OF THE RED**
21 **ROCK PROPOSAL?**

1 A. No. Again, PSO's acceptance of unsupported performance assumptions for the
2 modified Red Rock project conflicts with the requirement of section 3.4 of its
3 baseload RFP specifies that proposals should be based on "existing generating assets
4 that have a *proven operating history*." (Emphasis added.) Moreover, the AES PPA
5 included availability performance guarantee provisions that adjusted the capacity
6 charges for the project in the event the availability of the plant from which power
7 would be supplied dropped below a certain level. In light of this provision and the
8 lack of supporting performance data from existing USC units to confirm its
9 performance assumptions for the Red Rock project, PSO's failure to evaluate the
10 impact of lower performance levels for the project constitutes another major flaw in
11 the Company's economic evaluation supporting its selection of the Red Rock
12 proposal.

13 **Q. HOW SENSITIVE ARE THE RED ROCK PROJECT ECONOMICS TO THE**
14 **ASSUMED LEVEL OF PERFORMANCE OF THE UNITS?**

15 A. The primary justification provided by PSO for selecting a USC design for the Red
16 Rock project is the improved efficiency that is forecasted to be achieved due to the
17 higher steam temperatures and pressures at which such units operate. However, the
18 improvement in efficiency for USC units is only approximately 3% when compared
19 to the performance of supercritical coal-fired units, for which availability
20 performance has been demonstrated. With PSO's share of Red Rock fuel costs
21 forecasted to be in the range of \$35 million per year, this 3% heat rate benefit equates
22 to fuel cost savings of approximately \$1 million per year. However, each 1%
23 reduction in the assumed equivalent availability of the Red Rock facility equates to an

1 increase in replacement energy costs of approximately \$1.5 million annually.
2 Therefore, if the availability performance of the proposed Red Rock generating unit is
3 even slightly lower than the performance assumed by PSO in justifying the project,
4 the efficiency benefit that served as the primary basis for converting the Red Rock
5 project to a USC design will be eliminated.

6 **Q. ARE YOU CERTAIN THAT THE USC DESIGN WILL NOT PERFORM AS**
7 **PROJECTED BY PSO?**

8 A. No. However, the risks of lower availability performance appear to outweigh the
9 promise of potential efficiency savings for the USC technology. In fact, OG&E's
10 consultant, Sargent & Lundy, essentially reached a similar conclusion in its analysis
11 of subcritical versus USC plant designs, and recommended that OG&E select a
12 subcritical design for the Red Rock project. (See OG&E's Response to AG 2-24.)

13 **Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING PSO'S**
14 **EVALUATION OF RISKS OF THE RED ROCK PROJECT?**

15 A. PSO ignored risks of construction cost increases and lower-than-assumed
16 performance levels in its economic evaluations that supported its decision to select
17 OG&E's Red Rock proposal. In light of the lack of demonstrated performance data
18 for the USC design, and the fact that AES's PPA proposal provided fixed capacity
19 charges and certain performance guarantees, PSO's failures to consider the potential
20 for higher Red Rock plant construction costs and lower-than-assumed operating
21 performance are major flaws in its economic evaluation in support of the Red Rock
22 proposal. If the Commission decides to approve the Red Rock project, it would be

1 unreasonable to ask Oklahoma ratepayers to bear the risks of higher construction
2 costs and lower-than-assumed performance of the Red Rock facility.

3 **VII. OIEC RECOMMENDATIONS**

4 **Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING PSO'S**
5 **PROPOSAL TO ACQUIRE A 50% OWNERSHIP INTEREST IN THE RED**
6 **ROCK GENERATING FACILITY.**

7 A. If the current high level of natural gas prices continues, new coal-fired generating
8 capacity generally should be one of the most competitive alternatives to supply
9 baseload generating requirements over the current 10-year planning horizon.
10 However, the construction costs and associated operational risks of the proposed Red
11 Rock project are very high when compared to costs for other recently announced
12 coal-fired plants and costs under the AES PPA proposal that was rejected by PSO
13 based upon biased and flawed bid analysis. The scheduled in-service date of the
14 proposed Red Rock project has been delayed until February 2012. Moreover, PSO
15 could supply its system capacity needs without Red Rock through 2013 or 2014, by
16 relying upon short-term market capacity purchases. OG&E does not require new
17 baseload generating capacity until after 2014. Given these circumstances, and in light
18 of the high cost and risk associated with the Red Rock project, I recommend that the
19 Commission order PSO to immediately reopen its bidding process to obtain new
20 baseload bids with oversight and participation of an Independent Evaluator retained
21 by the Commission, as required by the Commission's competitive bidding rules.
22 This will ensure the integrity of the bidding process and allow the correction of flaws

1 in PSO's original RFP and bid evaluation process that have resulted in the selection
2 of a resource whose costs and performance appear to be significantly higher than
3 other baseload resources and which would require PSO's customers to bear undue
4 risk and uncertainty.

5 **Q. WHAT ARE YOUR RECOMMENDATIONS IF THE COMMISSION**
6 **DECIDES THAT THERE IS NOT TIME TO REOPEN THE BIDDING**
7 **PROCESS FOR PSO?**

8 A. The Red Rock project would be the first USC coal-fired generating unit constructed
9 in the United States in over 60 years. It would not be fair to ask Oklahoma ratepayers
10 to bear the increased costs and operating risks of the Red Rock project when other
11 lower cost alternatives with fixed capacity charges may be available to PSO.
12 Accordingly, if the Commission decides there is not sufficient time to reopen the
13 bidding process, I recommend that the costs of the Red Rock project that are
14 recoverable through rates be capped at a level that is consistent with the costs
15 evaluated by PSO in selecting OG&E's original Red Rock bid. I further recommend
16 that performance standards be established to assure that ratepayers are not harmed if
17 the performance of the Red Rock generating facility fails to meet the levels assumed
18 by OG&E and PSO in justifying their selection of the USC design for the Red Rock
19 project.

20 **Q. WHAT ARE THE SPECIFIC COST AND PERFORMANCE CAPS THAT**
21 **YOU RECOMMEND?**

22 A. First, I recommend that the Commission cap PSO's recovery of capital costs for the
23 Red Rock project and associated transmission facilities at a total cost of \$945 million

1 inclusive of AFUDC. This amount is consistent with the OG&E's original cost
2 estimate for the Red Rock project. (See Exhibit SN-15.) Second, I recommend that
3 the Commission adopt performance standards for the Red Rock unit, including a
4 minimum annual equivalent availability factor of 85% and a maximum annual net
5 heat rate of 9,000 BTU/kWh. These performance standards are consistent with the
6 level of performance assumed by OG&E and PSO in justifying the USC design.

7 **Q. WOULD THE COST CAP AND PERFORMANCE STANDARD PROVISIONS**
8 **YOU ARE RECOMMENDING ENSURE THAT PSO'S CUSTOMERS ARE**
9 **NOT HARMED BY A DECISION TO PROCEED WITH CONSTRUCTION**
10 **OF THE RED ROCK PROJECT?**

11 A. No. My alternative cost cap and performance standard recommendations would
12 provide customers with some protection against further capital or operating cost
13 increases that were not considered in justifying the project, and therefore would
14 provide a more equitable sharing of risks if the Commission decides to approve the
15 Red Rock project as proposed by OG&E. However, the AES PPA bid has a far lower
16 cost than the cap I am recommending and there could also be other available
17 alternatives to the Red Rock project that could better serve PSO's needs.

18 **Q. DOES THAT CONCLUDE YOUR TESTIMONY?**

19 A. Yes.