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

James M. Proctor

on behalf of

Oklahoma Gas and Electric Company

July 28, 2011

Q. **What is your name and business address?**

A. My name is James M. Proctor. My business address is 5555 West Sixth Street, No. Q5 Lawrence, Kansas 66049.

Q. **By whom are you employed?**

A. I am a self-employed consultant.

Q. **On whose behalf are you providing testimony?**

A. I have been retained by Oklahoma Gas and Electric Company to provide expert testimony on the Company's behalf.

Q. **What is your education and experience?**

A. I have a BBA from Washburn University with concentrations in accounting and mathematics. I also have an MBA from the University of Kansas with concentrations in finance and operations research.

I have approximately ten years experience in the regulation of public utility companies for two state utility commissions. In addition, I have approximately seventeen years experience as a consultant to state regulatory agencies, independent power developers, diversified traders and marketers of energy and other products, and regulated utilities and their non-utility subsidiaries or affiliates.

My experience working for state regulatory commissions includes being the Director of the Public Utility Division of the Oklahoma Corporation Commission and the Chief of Accounting and Financial Analysis for the Kansas Corporation Commission.

Q. **Have you testified before this Commission previously and had your credentials accepted?**

A. Yes. I have testified before the Oklahoma Corporation Commission on several occasions and my credentials were always accepted.

Q. **What is the purpose of your testimony in this proceeding?**

A. I am supporting the working capital included in the pro forma rate base for Oklahoma Gas and Electric Company ("OG&E" or "Company"). The components of working capital include cash working capital, net pension and benefit asset ("net PBA"), materials and supplies inventory, coal inventory, natural gas inventory, regulatory assets and liabilities, fuel oil inventory, prepayments and customer deposits. My testimony will explain ratemaking principles related to the test period analysis, rate base, rate of return on rate base, and measuring a utility's working capital requirements. Then, I will discuss, in detail, five of the working capital components included in the Company's rate base for the test year ending December 31, 2010. Those five working capital components include cash working capital, the net PBA, materials and supplies inventory, coal inventory and natural gas inventory. The remaining components of working capital are discussed in the final section of my testimony.

My discussion of these working capital components includes describing the role and measurement of the specific working capital components and illustrating the impact to OG&E's revenues and earnings should the Company not receive the ratemaking treatment recommended in my testimony. I will not discuss the remaining components of working capital here in as much detail because those components either do not involve adjustments or the adjustments are not material. However, the concepts I discuss regarding the measurement, and inclusion of working capital in rate base, generally apply to these other components.

Q. **How is your testimony organized?**

A. My testimony is organized in the following eight sections:

Section I.: Role of Working Capital in the Ratemaking Process

Section II: Utility Ratemaking Concepts

- Regulatory Test Period Analysis Fundamentals
  - Principles of Rate Base/Rate of Return Regulation
  - Methods for the Measurement of Working Capital

Section III: Cash Working Capital

- Elements of Cash Working Capital

- Objectives for the Inclusion of Cash Working Capital
- Basis of Recognizing and Including Excluded Components

Section IV: Net Pension and Benefit Asset

Section V: Materials and Supplies Inventory

Section VI: Coal Inventory

Section VII: Natural Gas Inventory

Section VIII: Other Working Capital

- Regulatory Assets and Liabilities
- Fuel Oil Inventory
- Prepayments
- Customer Deposits

SECTION I: ROLE OF WORKING CAPITAL IN THE RATEMAKING PROCESS

Q. **Generally, what is the role of working capital in ratemaking?**

A. Working capital represents the required funds necessary to support ongoing utility operations. In ratemaking, the objective for a state regulatory agency is to estimate and measure the amount of working capital necessary, on average, to sustain the utility over the course of a series of twelve monthly periods. That is, the required level of working capital should represent the amount necessary to meet the working capital needs on an ongoing basis, annually, for the years during which a company's prospective utility rates will be charged. Once that amount of working capital has been quantified, it should be included in the test year rate base and, thus, receive a full rate of return for the company's shareholders. Later in my testimony, I will address the role and measurement of specific working capital components.

Q. **Why do you believe it necessary to discuss concepts of utility ratemaking in order to explain your working capital recommendations?**

A. I certainly understand that the Oklahoma Corporation Commission ("Commission"), Commission Staff ("Staff") and other participants to this proceeding have knowledge of ratemaking concepts. However, I believe the relationship between working capital and

revenue requirements is widely misunderstood. This problem is particularly true for the cash working capital component of working capital.

Q. **Why do you believe it is necessary to discuss concepts of utility ratemaking in order to explain your working capital recommendations??**

A. Too frequently, commissions have not provided an adequate amount of working capital in rate base to sustain the utility's operations. Failing to provide adequate working capital prevents the utility from having a fair opportunity to earn its authorized return. As I will discuss later in my testimony, a utility's potential earnings shortfall is probably the greatest with respect to common misunderstandings regarding the cash working capital component of working capital. That misunderstanding has led to regulatory bodies excluding large cost of service components such as depreciation and amortization expense, deferred income tax expense, and net income from a properly designed cash working capital study, thus potentially leaving shareholders with a significant earnings shortfall. Often, the argument provided to support those exclusions is that these components do not involve cash flow expenditures during the test year. That argument will be dispelled later in my testimony. I will clearly demonstrate that the argument for exclusion of these elements from a cash working capital analysis is erroneous and results in setting a deficient rate base causing deficient cash flow and earnings for common equity investors.

SECTION II: UTILITY RATEMAKING CONCEPTS

Regulatory Test Period Analysis Fundamentals

Q. **What is the regulatory agency's responsibility in determining utility rates based on the test period approach?**

A. Regulatory commissions are responsible for, among other obligations, fixing rates at just and reasonable levels. These rates should provide the utility with a reasonable opportunity to recover ***all*** costs prudently incurred in providing utility service. Recoverable costs include operations and maintenance expenses, depreciation and amortization expense, income and other tax expense and a fair return on investments in: (a) utility plant; (b) other utility assets; and, (c) the working capital required to provide

and maintain utility service. The sum of these costs is usually referred to as either the cost of service or revenue requirement for the utility.

Q. **Over what period of time are the recoverable costs measured?**

A. A twelve month period is used to measure the costs of providing utility service. That period of time is commonly referred to as the test year. Test year measurements may be restricted to historic sales, expenses and investments in rate base. However, in most circumstances utility commissions permit adjustments to the recorded historic sales, expenses and rate base to make the test period representative of revenue requirements going forward after the test year-end. Some commissions may allow test period data to be fully developed through forecasts of revenue requirements. Whichever test period concept is used, the primary objective must be to estimate the level of sales, expenses and rate base representative of those conditions expected during the period new utility rates will be in effect, not for the historic test year.

Q. **Is it possible for a commission to rely too much on historic test year costs for setting prospective utility rates?**

A. Yes. Sometimes regulators are too conservative when measuring test year cost of service. Generally, the conservative approach is falsely justified on the presumption that historic costs are actual, and known and determinable. It is believed that the historic costs are, therefore, less speculative than those costs from test periods with either extensive pro forma adjustments or forecasted information. However, those historic test period costs are only actual, and known and determinable, for the historic test year. Remember, the test period objective for establishing utility rates is to develop them based on cost levels representative of the prospective period of time for which those rates will be charged. Otherwise, there exists a mismatch between the historic costs and those prospective costs which will occur.

Furthermore, regulatory agencies relying heavily on historic test year cost measurements do not overcome the reality that they are projecting future costs. That is, when a commission sets utility test period costs using largely historic estimates, they are projecting the future will be the same, or similar, to the past. Because it is impossible to

avoid projecting costs into the future when measuring the test period cost of service, the regulator should do so implementing certain relevant and determinable cost adjustments to historic measurements to make the test period costs more representative of the time period rates are in effect. Such cost adjustments may require estimating, measuring and including expenses and rate base amounts forecasted, or incurred, after the historic test year.

Principles of Rate Base/Rate of Return Regulation

Q. **What is the most common approach used to determine a utility's revenue requirement?**

A. The most common approach used to determine a utility's revenue requirement is the rate base/rate of return approach. This approach involves calculating the recoverable costs, separately, and then adding them together. As mentioned above, recoverable costs include: (1) operations and maintenance expense, (2) depreciation and amortization expense, (3) income and other tax expense; and, (4) a fair rate of return on rate base including working capital.

Q. **What does the rate of return applied to a utility's rate base include?**

A. The rate of return represents the weighted-average for the individual percentage costs of capital incurred by the utility to finance its rate base. Commonly, those capital costs include the costs of debt and equity used to fund rate base investment. However, there may be other sources of financing as well.

Q. **What is the ratemaking objective under the rate base/rate of return approach?**

A. The ratemaking objective under the rate base/rate of return approach is to set the revenue requirement, i.e., the cost of service, at a level to allow the utility a fair opportunity to recover, through its rates, all prudently incurred expenses and a predetermined rate of return on the utility's prudent investment in utility plant, other utility assets and working capital. That is, in addition to recovering prudently incurred expenses, under this approach the utility should be allowed the opportunity to recover its debt costs and earn a fair return for its common equity investors for their investment in the utility.

Q. **Should working capital and other rate base investments receive a full overall rate of return?**

A. Yes. Commissions generally recognize that each investor's dollar prudently invested in working capital, and other rate base items, should earn a full overall rate of return through customers' rates. Now, that full return may be recovered through some combination of current and future rates.

For example, the return on investment will be recovered through current rates when the working capital, or other rate base component, is included in the test period rate base used to establish current utility rates. The return will be recovered through future rates when the utility's working capital, or other rate base investment, is authorized to accrue financing costs for capitalization and inclusion in a subsequent test period's rate base. The funding for a utility's investment in plant under construction is the most obvious example of financing costs being deferred for recovery in future rates, that is, being recovered after the constructed plant is placed in service.

Q. **Isn't it common for a utility to capitalize, for recovery in future rates, only the debt financing costs with respect to plant under construction?**

A. Yes. It is common for utility commissions to only allow debt financing costs, on plant under construction, to be accrued and capitalized for recovery in future rates. Frequently, it is the utility's short-term debt cost that is capitalized during construction, but long-term debt and equity costs are at times capitalized also.

Yet, even when only short or long-term debt costs are capitalized, the utility still earns, and recovers through customers' current or future rates, a full overall rate of return on each dollar prudently invested in plant, and other rate base items. This is the case because, even if only short or long-term debt costs are capitalized to construction costs, the remaining debt and equity financing costs incurred to fund the utility's other investments and operations are allocated in greater proportions to current rate base. That is, current rates include equity financing costs that otherwise could have been allocated to construction financing and collected in future rates through recovery of then constructed plant in service.

Therefore, as the discussion about capitalized construction financing costs illustrates, each investor's dollar prudently invested in working capital, plant and other rate base items, on average, correctly earns a full overall rate of return through customers' rates either, currently, or in the future. That is, investors are made whole for their financing costs.

Q. **Should regulators take care in deriving the cost of service?**

A. Yes. It is important for a regulatory body to be diligent in establishing rates. The components of the rate base/rate of return formula should represent the commission's best estimate for the level of costs necessary to sustain utility operations and earnings going forward. If rates set under the formula overstate the sum of the expected costs going forward, the customers will pay higher rates and common shareholders will receive greater earnings. If rates set under the formula understate the sum of expected costs going forward, the customers will pay lower rates and common shareholders will receive lesser earnings. Neither of those outcomes is appropriate, particularly if the difference between estimated and actual costs is substantial.

Methods for the Measurement of Working Capital

Q. **Are various approaches used to estimate working capital requirements?**

A. Yes. Regulators have employed various strategies for estimating a utility's working capital requirement. For this particular rate case, OGE's working capital includes: cash working capital; prepayments; materials and supplies inventory; fuel inventories; regulatory assets and liabilities; customer deposits; and the net PBA. In developing OGE's working capital needs for these investments, I have employed several different approaches. I will explain the reasons supporting the approaches later in my testimony. However, each different approach is tailored to the specific circumstances affecting respective components of working capital investment.

Q. **What are the various approaches used to determine working capital requirements?**

A. Generally, regulatory commissions apply some combination of several measurement techniques to estimate utility working capital requirements. For working capital

components that involve an inventory, or other utility asset investment balance, such as for fuel, materials and supplies or regulatory assets, techniques include: averaging historic month-end test year balances; using a historic test year-end balance; averaging historic month-end test year and month-end post test year balances; using an historic balance at some month-end after the end of the test year; and, projecting or forecasting balances. A commission may use various combinations and variations of these techniques. But, the goal should always be to select a method that reasonably represents expected levels of investment during the period the new rates will be charged.

Determining cash working capital requirements is a more complex matter than for inventories or regulatory asset balances. There are generally three methods which have been traditionally employed by regulatory commissions for measuring cash working capital. Those methods include: 1) a 45-day standard formula approach; 2) a balance sheet approach; and, 3) a lead-lag study.

While advantageous for their simplicity, neither the 45-day standard formula nor balance sheet approach is as accurate or comprehensive as the lead-lag approach. Because OG&E prepared a lead-lag study, which I reviewed and believe contains all the correct assumptions and applications,[1] my testimony regarding cash working capital focuses only on the lead-lag study approach and how such a study should be correctly applied in determining cash working capital requirements. Further, since the Staff and other parties to Oklahoma rate cases have not recently proposed either the 45-day standard formula or balance sheet approaches for large investor-owned electric utilities, I find it unnecessary to discuss those methods here. However, much of my testimony will be dedicated to explaining the correct application of a lead-lag study in determining cash working capital requirements.

Q. **Please illustrate the importance of measuring working capital such that the amount in rate base is representative of prospective needs rather than historic balances.**

A. For one reason or another, historic monthly averages or test year-end balances may not be representative of prospective working capital requirements. When they are not representative, but still used for ratemaking, the impact to rates and the utility's earnings

[1] The lead lag study is contained in Schedule E-1 of the MFR package.

can be significant. For example, let's assume a strict historic 2010 test year is used. Under such scenario, some working capital and other rate base components are based on test year average monthly balances and others on test year-end balances. By the time the audit and hearing process is completed, new rates could be expected to go into effect beginning around January or February, 2012. When 2010 test year-end balances are used for measuring working capital, rates would become effective a full twelve months after the end of the 2010 test year. Also, if rates become effective January 2012, any historic working capital measured based on 2010 test year average balances would be eighteen months old. Such is the case because a 2010 test year average monthly balance reflects the theoretical amount of capital required on July 1, mid-point of the 2010 test year.. When test year-end balances are used for measuring working capital, a similar calculation finds that rates are effective twelve months after test year-end.

If the new electric rates are to be charged for two or three years, the potential problem is even more severe. When costs and investment levels remain relatively stable after the test year, the use of historic data, predominantly, serves well when measuring rate base. However, it is not always the case that costs and investments levels remain stable. Working capital requirements for such components as fuel and materials and supplies may vary significantly due to inflation, changes in the required quantity of inventories and changes in the type of assets in inventory.

Also, uncontrollable events in conjunction with prudently negotiated purchase and transportation contracts may cause an inventory or other working capital balance to be larger than normal for a period of time. Because such events are uncontrollable, and do occur occasionally, a commission should consider including a return on the additional working capital caused by the uncontrollable event, especially when such event is prudently managed by the utility's management to mitigate harm. A good example of such an uncontrollable event that must be managed by the utility is the coal inventory levels, which will be discussed in detail below.

Q. **When would it be appropriate to measure working capital using average balances?**

A. Some working capital balances tend to fluctuate through any given twelve month period. For example, materials and supplies inventories tend to be somewhat volatile overtime

because their use is not constant. This is particularly the case for expensive plant assets in inventory. When working capital balances vary over time, an average of balances may provide a better estimate of the on-going investment for those respective assets. However, based on the aforementioned problems of using historic balances, it is necessary to extend the averaging beyond test year-end to capture levels of investment more closely in line with prospective requirements. In certain cases, it may be necessary to forecast or project a balance for working capital amounts when investment in a particular component is increasing.

Q. **When would it be appropriate to measure working capital using period ending balances?**

A. Some working capital and rate base asset balances tend to increase over time. This is generally indicative of electric plant. Some working capital inventory balances may fluctuate but also increase over time. If working capital assets, such as inventory, are increasing, then it may be appropriate to measure that working capital component at test year-end. As for averaging working capital balances, it may be necessary to measure the period ending balance at a month-end beyond the test year, or use a forecast, to capture levels of investment more closely in line with prospective requirements.

SECTION III: CASH WORKING CAPITAL

Elements of Cash Working Capital

Q. **Please define cash working capital.**

A. Cash working capital represents the amount of cash funding required to support the operational requirements of the utility for the period between when cash must be spent by the utility in providing its services and when cash is received from customers when those customers pay for their utility service. That is, cash working capital represents that amount of cash, on average, that a utility invests during a specified annual period, through equity or debt financing, in addition to investors' investment in plant and other separately identified rate base assets.

Q. **Is cash working capital a component of rate base?**

A. Yes. Cash working capital is included in rate base as a net positive, or net negative amount. That is, when the utility's investors provide the net funding, the return requirement is positive and when ratepayers provide the net funding, the return requirement is negative. Therefore, cash working capital must be measured with care to assure the company receives recognition for cash working capital provided by its investors and the customers receive recognition for cash working capital funded by them through utility rates.

Q. **What are the components of rate base?**

A. Rate base represents the value of investor funded plant and other investments required for providing service to the utility's consumers. Specifically, it includes plant, materials and supplies inventory, fuel inventory, prepaid expenses, regulatory assets and liabilities; miscellaneous customer provided capital and cash working capital. The cash working capital component of rate base includes cash prudently funded by investors in the utility operations that has not been accounted for elsewhere in rate base.

Q. **Should investors be allowed to earn a return on all funds invested in utility rate base including cash working capital?**

A. Yes. Regulatory economics and law generally require that investors be allowed a fair opportunity to earn a reasonable return on the value of their prudent investment in rate base. Since utility rate base is the amount by which the commission-authorized rate of return is applied to determine pro forma operating income, if the cash working capital component of rate base does not include all cash prudently invested by investors in the utility, the equity investors' actual return will be deficient.

Further, because cash working capital is a component of rate base, there should be a return requirement associated with that investment. That rate of return should equal the same overall cost of capital applied to other rate base assets. Keep in mind through, as stated earlier in my testimony, sometimes the return requirement for cash working capital is positive and sometimes it is negative. So, the return allowed for cash working capital should reflect the proper timing sequence between when cash is funded by utility

investors and when cash is provided by customers and this proper timing sequence is determined by a lead-lag study.

Q. **What method of measurement was employed by the Company to measure cash working capital in this cause?**

A. The Company employed a comprehensive lead-lag study for the test period ending December 31, 2010. The major objective of a lead-lag study is to determine the amount of investors' cash invested in the utility in addition to that invested for other rate base components such as net plant. Lead-lag studies must measure lags and leads, consistently, by analyzing all sources and uses of cash.

Q. **What do the terms lead period and lag period refer to?**

A. The lead period relates to the time period, in days, between recording a cost and paying for such cost. The lag period relates to the time period, in days, between when utility service is provided and when receipt of cash for such services is received from customers. A lead-lag study consists of a comprehensive review of test period transactions to determine an overall net-lag day amount to be used in determining cash working capital requirements.

Q. **Will you provide an example of a lead-lag calculation?**

A. Yes. For example, if service revenues, based on a weighted-average of revenues, have a 15-day lag period and costs, based on a weighted-average of costs, have a 10-day lead period, the company's recovery of the test period cost of service has a 5-day net revenue lag (15-day lag period minus 10-day lead period). That means investors must fund, using cash working capital, 5 days worth of the test period cost of service. Thus, in this example of the lead-lag calculation, the cash working capital requirement is determined by multiplying the test period total cost of service by 5 (net revenue lag) and dividing that product by 365 (days in a year). The resulting number is the amount of cash working capital that should be in rate base.

Q. **Are there potentially other cash working capital considerations in addition to the amount calculated from multiplying the test period total cost of service by the net revenue lag and dividing that product by 365?**

A. Yes. There may be additional sources of cash working capital that have not been fully recognized through the lead-lag study. One must examine a company's test period balance sheet to find these items and then include them as either additions to or subtractions from the cash working capital requirement determined above. The additions to and subtractions from cash working capital consist of assets and liabilities, respectively, which have not either been, but should be, accounted for in rate base or customer provided capital.

For example, accrued vacation pay represents an amount for employee compensation not yet paid out in cash when recorded as an expense. Because a company recovers that expense through rates anyway, and a company's lead-lag study does not generally determine a specific lead time for the cash payment of vacation pay, one must subtract the average test period balance of accrued vacation liability from cash working capital to recognize it as customer provided capital. If the company had determined a specific lead time for vacation pay expense, the average test period balance of accrued vacation liability would not have been subtracted from rate base.

Q. **What were the results of the lead-lag study?**

A. The results of the study indicate OG&E's investors provide the net funding for cash working capital and, therefore, the return requirement in this case is positive. Specifically, the pro forma cash working capital investment is $17,581,155 for the test period.[2]

Q. **What, then, is the adjustment to test period rate base?**

A. Since OG&E does not assign a value for cash working capital in the test year until it can be calculated from the lead lag study, OG&E has reflected its cash working capital requirement as a pro forma adjustment. The adjustment to cash working capital is shown

[2] Schedule E-1 in OG&E's Application, Cause No. PUD 201100087, filed July 28, 2011.

as Rate Base Adjustment No. 11. Specifically, the adjustment increases the test period's balance of cash working capital from $0 to $17,581,155. Therefore, the pro forma level of cash working capital is $17,581,155.

Q. **Are there certain investments that some parties to the Company's previous rate cases suggested should not receive rate base treatment through cash working capital?**

A. Yes. Certain arguments presented before the Commission have supported excluding four components of OG&E's revenue requirement from the lead-lag study in determining the amount of cash working capital investment allowed in rate base. Those components include depreciation and amortization expense, deferred income tax expense, amortization of the accumulated deferred investment tax credit ("ADITC") and net income. The arguments differ somewhat, but each argument draws the same conclusion regarding exclusion of these costs from the lead-lag study.

Q. **Do you agree with those arguments for excluding depreciation and amortization expense, deferred income tax expense, amortization of ADITC and net income from the lead-lag study?**

A. No. As explained in greater detail below, I believe that these revenue requirement components should be considered in determining the amount of cash working capital that should be included in rate base.

Q. **Generally, what is the impact to OG&E's common equity investors from not including these components in the lead-lag study?**

A. If depreciation and amortization expense, deferred income tax expense, amortization of the ADITC and net income are excluded from the lead-lag study, OG&E's common equity investors will be denied a fair opportunity to earn a return on a portion of cash working capital funding the electric operations of the Company. Each of these components represents a cost that a utility uses cash to fund. Since investors provide the cash to pay for such costs, they are entitled to a return on their investment unless such

costs are shown to be imprudent, providing benefits to non-utility businesses; or funding non-jurisdictional operations of the Company.

Q. **Specifically, in terms of dollars of rate base, revenues and earnings, how much could the Company be denied if these costs are incorrectly excluded from the lead-lag study?**

A. In Exhibit JMP-1, attached to my testimony, I include a calculation for the amount of rate base, revenues and earnings, the Company could be denied if these costs are incorrectly excluded from the lead-lag study. In that exhibit, the Commission can see that the pro forma rate base, as filed by OG&E, could be deficient by $51,452,366. Assuming OG&E's proposed return on equity, weighted-cost of debt, capital structure, and the rate base deficiency above, the annual short fall in cash revenues and after-tax cash flow to OG&E's shareholders could be $6,506,306 $3,984,520.

Q. **How will the remainder of your testimony regarding cash working capital be organized?**

A. I will separate my discussion into three sections. They are: (1) a conceptual overview of cash working capital and the objective for including cash working capital in rate base; (2) the basis for including depreciation expense, deferred income tax expense, amortization of ADITC and net income in a properly designed lead-lag study; and, (3) specific comments addressing the flaws inherent in arguments contesting consideration for and inclusion of cash requirements attributed to depreciation expense, deferred income tax expense, amortization of ADITC and net income in cash working capital and, thus, in rate base.

Objectives for the Inclusion of Cash Working Capital

Q. **Why is cash working capital included in rate base?**

A. Cash working capital is included in rate base to synchronize the value of the total collection of rate base assets with the value of un-recovered cash prudently invested in the utility for a specified test period. That is, it represents an amount of cash investment not yet recovered through customers' revenues, although also not included in other rate

base, or deferred assets, that are separately earning or accruing a return, respectively. Cash working capital is the amount of cash that investor's provide the utility, but could fall through the cracks if it is not included in other places in rate base. Cash working capital is therefore included in rate base to ensure that any cash not otherwise reflected in rate base earns a return. Put another way, for the rate base to be correctly measured for a specified test period, the cash working capital component must be compatible to (or synchronized with) other rate base items in order to match rate base with the amount of cash invested in the utility's operations.

Q. **If cash working capital is not synchronized with other areas of rate base, what will be the ratemaking result?**

A. If cash working capital is not synchronized with other areas of rate base, the rate base will not function properly and, thus, earnings will be deficient. For example, if rate base components, such as net plant in service, do not accurately represent the un-recovered investment in utility plant for a given test year, and test year net plant is not adjusted to correct that difference, cash working capital should be provided to correct that difference. Otherwise, the rate base will not match the cash invested, on average, in the utility for the test year.

Q. **Will you please provide an example of that situation?**

A. Yes. Cash working capital needs to be provided for test year depreciation expense.[3] This is necessary because the test year-end plant levels in rate base are decreased by accumulated depreciation. Now, at test year-end, the Company has not yet received cash through sales revenues for a portion of the accumulated depreciation removed from rate base. The investors should be provided a full return on that portion of accumulated depreciation, removed from rate base, until it receives the depreciation-related cash through revenues.

[3] I will address the cash flow related to depreciation expense in more detail later in my testimony. The discussion of depreciation expense and accumulated depreciation here is simply to provide an example to illustrate the relationship between cash flow, non-cash expense items and rate base.

Q. **What is the ratemaking objective behind decreasing plant investment for accumulated depreciation?**

A. In utility ratemaking, the objective behind decreasing plant investment, for accumulated depreciation, is to not allow a return on plant investment for which investors have already recovered cash through customers' revenues. However, at test year-end, there exists an amount of depreciation expense recorded on OG&E's books, and used to decrease rate base through recording accumulated depreciation, even though that depreciation expense will not yet have been received from the Company's customers through revenues.

The cash recovery for a portion of depreciation expense will have not been recovered at test year-end because of the revenue lag.[4] That is, the net plant balance (i.e., plant less accumulated depreciation) included in rate base is deficient. It is deficient by that portion of recorded accumulated depreciation not yet received, in cash, through OG&E's utility rates. Specifically, the un-recovered cash flow, due the Company for its recording of depreciation expense, is incorrectly attributed to the Company's shareholders even though that amount of cash is still in the hands of the ratepayers.

Q. **How else could the Commission correct this rate base shortfall if cash working capital is not provided?**

A. The Commission has two options to ensure that any cash not otherwise reflected in rate base earns a return. The first option is to include cash working capital in rate base. If the Commission does not choose to allow a cash working capital allowance for the un-recovered cash not otherwise included in rate base, the other option is to adjust rate base in some other way. For example, with regard to the above discussion regarding unrecovered test year-end depreciation expense, OG&E could alternatively increase the rate base by decreasing the accumulated depreciation balance accordingly. The decrease to accumulated depreciation should be equal to the amount of depreciation expense for which cash had not yet been recovered through customers' revenues due to the revenue lag.

[4] The lead-lag study found that the revenue lag is 39.83 days. That means that at test year-end 39.83 days of depreciation expense had not been received from ratepayers' through their payment for electricity services.

Basis for Recognizing and Including Excluded Components

Q. **What will you demonstrate in this section of your testimony?**

A. I will explain the basis, and required treatment, for including depreciation expense, deferred income tax expense, amortization of ADITC and net income in a properly designed lead-lag study. Inclusion of these costs in the lead-lag study is absolutely necessary to match test year cash investment with test year rate base. If these components are not synchronized with other areas of rate base, the shareholders will not receive a return on their full prudent investment in OG&E's Oklahoma jurisdictional electric utility.

Q. **Do you think your application of the lead-lag study provides a reasonable amount for cash working capital?**

A. Yes. I believe the principles employed in the Company's lead-lag study are theoretically sound. In accomplishing that outcome, I have employed the total revenue requirements approach. Under that approach, all components of the revenue requirement are examined in arriving at a reasonable value for cash working capital. All components of the revenue requirement must be examined because all expenses and earnings requirements are directly related to cash expenditures or cash receipts at some point during the provision of utility service.

Q. **In previous cases have some other parties disputed the Company's approach?**

A. Yes. A review of the testimony and pleadings in previous cases finds that certain witnesses have a different opinion regarding the elements of cost of service to be included in a lead-lag study. I will address their arguments in more depth later in my testimony. However, in general, these witnesses feel the study should be limited to costs that involve cash expenditures during the "current period".

That approach unfairly excludes part of the Company's full investment in the utility. That is, those witnesses' positions fail to recognize, for example, that un-recovered investments made in previous historic periods should continue to earn a return until the investment has been recovered through customers' revenues. Their flawed reasoning has led them to advocate arguments that have the effect of not recognizing all cash

investments outstanding, and caused by the revenue lag, for depreciation expense, deferred income tax expense, amortization of the ADITC, and net income in the lead-lag study.

Q. **Why do you believe the lead-lag study should include depreciation expense, deferred income tax expense, amortization of the ADITC and net income?**

A. Because the basic reason for including cash working capital in rate base is to compensate investors for investing cash in the Company and these four categories all affect cash flow and relate to rate base investments.

Q. **In explaining the need for depreciation expense in the lead-lag study, please explain in detail how investors should receive a full return on and recovery of cash invested in plant.**

A. An investor in OG&E receives a *return on* their investment in plant through the Commission including such plant in the Company's rate base. The investor receives *recovery of* that investment in plant through the Commission including such plant's depreciation expense in the Company's operating expenses.

A utility's net plant, and thus rate base, is decreased through recording depreciation expense. At the time depreciation expense is recorded, that means rate base is decreased, even though the prospective recovery of cash flow for such depreciated investment will not have been received until customers' bills are paid. In the interim, the investor continues to fund the un-recovered depreciation expense, and investors should be compensated for the time value of money for that continued investment.

In this case, the Company collects cash for depreciation expense through revenues, on average, about 39.83 days after service is rendered. Unless this lag is reflected in the cash working capital allowance, and its related cash investment is included in rate base, that portion of investor supplied cash will not have an opportunity to earn the Company's proposed return during the lag period. To correctly recognize, and compensate investors

for, the investment related to depreciating plant, the Commission should assign a zero lead time for depreciation expense in the cash working capital calculation.[5]

As indicated earlier, if the Commission does not choose to allow a cash working capital allowance for the un-recovered test year-end depreciation expense, it should alternatively decrease accumulated depreciation by the amount of un-recovered depreciation expense at test year-end due to the revenue lag. The Commission must choose one of these options to synchronize the value for the total collection of rate base assets with the value of un-recovered cash prudently invested in the utility for the test year.

Q. **How else can you illustrate this deficiency?**

A. This situation can be illustrated by discussing a customer deposit in a savings account. Let's say someone had deposited $1,000 in a bank savings account. After 30 days, that customer visited the bank to withdraw $100 from the savings account. The bank confirms the customer's balance at $1,000 then subtracts $100 from the balance, for the requested cash withdrawal, leaving $900 in the account earning interest. However, the bank teller then explains to the customer that she will not receive the $100 cash withdrawal for 39.83 days and, during that lag period, she will not receive interest earnings on that $100 cash withdrawal. In essence, the customer has to wait the lag period to receive the $100 withdrawal and will only receive interest on $900 of her $1000 investment. The customer should be entitled to the full amount of interest for the full $1000 dollars until the customer receives the $100 withdrawal.

To apply this analogy to a utility's cash working capital, a utility's investors make a "deposit" with the utility. They earn interest by accruing a return on their deposit and, as they are paid back (through depreciation expense), their principal balance in the "account" (i.e., the investment in plant) is reduced. It would be unfair for the utility investor to see the principal balance diminished, not earn a return on that diminished balance and have a delay in receiving recovery of the depreciation expense.

[5] In assigning a zero lead time to depreciation expense, one recognizes that prior to recording plant investment to rate base the company has already expended cash for that investment. Therefore, no additional lead time is needed when recording depreciation of that plant. That is, the cash related to the depreciation expense was invested in prior periods during construction or acquisition of the plant asset.

Q. **How should deferred income tax expense be treated in the lead-lag study?**

A. The treatment for deferred income tax expense is the same as that for depreciation expense discussed above. In determining revenue requirements, the provision for deferred income tax expense is included in expenses and the balance of accumulated deferred income tax ("ADIT") expense is deducted from rate base. Just as is the case with depreciation expense and accumulated depreciation, the ADIT is recorded as a liability upon recognition of deferred income tax expense in the income statement, yet the deferred income tax expense has not been collected from customers, on average, until the end of the revenue lag period.

For that interim period of 39.83 days, continued investor funding exists equal to the un-recovered deferred income tax expense. The investors should be compensated for the time value of money for that investment. That objective is satisfied from including 39.83 days of deferred income tax expense in cash working capital and, thus, authorizing the Company to earn its authorized return on that cash investment.

As for depreciation expense, to correctly recognize, and compensate investors for, the investment related to ADIT, the Commission should assign a zero lead time for deferred income tax expense in the cash working capital calculation. If a cash working capital allowance is not provided here, the Commission must adjust rate base to remove that portion of test year-end ADIT liability related to un-recovered deferred income tax expense.

Q. **Is there any difference between how deferred income tax expense and depreciation expense is treated in the lead-lag study?**

A. Yes, there is a slight difference. With depreciation expense, a utility's investors are repaid for their investment previously contained in rate base. With deferred income tax expense, the utility's investor is being "loaned" money from customers to pay future income taxes and, in return, customers are benefiting from greater amounts of ADIT

(which is a reduction to rate base).[6]

However, the principle is the same: the cash "loan" received from the customers through the payment of deferred income tax arrives to the Company 39.83 days after the ADIT has been recorded as an offset to rate base. That is, during the revenue lag of 39.83 days, the Company's rate base has been decreased for ADIT, but the cash, in the form of revenue, has not been received from customers. Therefore, the Company is paying a return to customers, due to the ADIT offset from rate base, for 39.83 days, on average, before the cash "loan" is received through customers' revenues.

Q. **How else can you illustrate this deficiency?**

A. This situation is analogous to a bank loan. Let's assume a customer goes to the bank to apply for a loan of $1,000. The bank approves the loan application with an interest rate of 10%, but agrees to disburse the loan, in cash, to the customer in 39.83 days. However, the bank charges the interest rate of 10% during the revenue lag period of 39.83 days even though the customer does not have the cash loan yet.

Q. **How should amortization of the ADITC be treated in the lead-lag study?**

A. As accumulated deferred investment tax credits are amortized, that amount of amortization decreases income tax expense collected through revenue requirements. The correct treatment for the expense offset created from amortizing ADITC is similar to that treatment provided for depreciation expense and deferred income tax expense in the lead-lag study.

Unlike the case for recording ADIT, rate base is not adjusted from recording ADITC due to the tax law prohibiting the full benefit of investment tax credits being transferred to the utility's customers. That is, the Company was not required to recognize ADITC as cost-free capital, therefore, its amortization does not increase rate base.

[6] Through the ratemaking process, customers receive a "return" on the funds provided through rates, due to the Company's rate base being decreased by ADIT, the accumulated balance of funds not yet paid in cash to the government. That is, absent the Company recovering customer contributed capital in the form of deferred income tax expense, the Company's rate base would be larger, thus requiring a larger return for investors. In future periods, as the Company pays off the deferred income tax liability to the government, the amount of ADIT subtracted from rate base correspondingly decreases and, thus, rate base increases.

Still, that reduction to the balance of ADITC occurs before the customers have the related benefit from paying the lower income taxes through rates. One can see that the primary difference here is that correctly treating amortization of ADITC in the lead-lag study decreases cash working capital requirements, thus benefiting customers.

Q. **What is the correct lead time for the amortization of the ADITC?**

A. As for depreciation expense and deferred income tax expense, the Commission should assign a zero lead time for amortization of the ADITC in the cash working capital calculation.

Q. **Why should net income be included in the lead-lag study with a zero lead time?**

A. Conceptually, this matter is the same as for depreciation and deferred income tax expenses. Net income is part of the cost of service included in utility rates. That is, a company receives the cost of capital, and thus its earnings, through customers' revenues. Customers' revenues, on average, are collected about 39.83 days after providing them utility service. Therefore, the investors must wait for recovery of cash earned on their investment in providing service until the end of the lag period.

In effect, the investors' earned return is still held by the customers even though utility service has been provided to them by the utility. Absent cash working capital treatment, the Company's earnings, held by the customers, will not accrue a return even though the Company does not have possession of the cash.

Q. **Are you aware of arguments that lead–lag studies should only include consideration of operating expenses that involve a cash outlay during the current period?**

A. Yes. The fundamental argument is that only costs that involve cash expenditures during the current period should be in the lead-lag study. Presumably, this means the test year as the "current period".

Q. **Should lead-lag studies only consider cash expenditures during the current period?**

A. No. As I explain above, all components of the revenue requirement must be considered in a cash working capital analysis because all expenses and the cost of capital, incurred in

providing service, are directly related to either cash expenditures or cash receipts at some point during the provision of utility service. Remember, the basic reason for including cash working capital in rate base is to compensate investors for the time value of money for investing in the Company.

Q. **Is the book, *Accounting for Public Utilities,* typically used as a source document for utility ratemaking?**

A. Yes.

Q. **Is the book, *Accounting for Public Utilities* a reliable source for ratemaking concepts and applications?**

A. Yes. The book is a highly regarded text for understanding ratemaking concepts and applications. Further, regulatory bodies use it as a learning tool for understanding accounting, financial and economic principles as applied to ratemaking.

Q. **Do you believe arguments urging the exclusion of non-cash expenditures demonstrate a general misunderstanding for the definition and application of cash working capital as set forth in the book, *Accounting for Public Utilities*?**

A. Yes, I believe so. The pages of § 5.04 of the book, *Accounting for Public Utilities*, discuss: (1) the application of lead-lag studies; and, (2) the purpose for placing cash working capital in rate base. Clearly, the text explains that depreciation expense and deferred income tax expense should be included in lead-lag studies with a zero lead time.

Q. **Are arguments against assigning a zero lead time to depreciation expense and deferred income tax expense incorrect?**

A. Yes, I believe it is correct to include depreciation expense and deferred income tax expense in the lead-lag study with a zero lead time. It is not totally clear to me why some argue that assigning a zero lead time to depreciation and deferred income tax expense is incorrect. The concept seems straight forward to me. However, one witness has previously stated that the zero lead-time assumption is flawed because it assumes that a

rate case occurs each month to capture the changes in rate base levels. I believe that statement demonstrates a misunderstanding of this issue.

Q. **Please explain why such a view of the application of zero lead time demonstrates a misunderstanding of the issue.**

A. Assigning a zero lead-time to depreciation and deferred income tax expense does not require any assumptions concerning the frequency of test years and rate cases. As I explain above, signing a zero lead-time to these expenses is based on the fact that at test year-end, for any test year used to establish rates, there will be entries recorded to accumulated depreciation and ADIT for amounts of cash that will not have been recovered by the Company through revenues.

Due to these entries recorded to accumulated depreciation and ADIT, test period rate base will be reduced, but there will be un-recovered cash flow excluded from rate base, caused by the revenue lag, unless an allowance for cash working capital is provided to offset such deficiency. Since the revenue lag represents the period for which the Company has not yet recovered cash for these expenses, although rate base has already been decreased from recording their related accumulated depreciation and ADIT, one must assume a zero lead-time for depreciation and deferred income tax expense in order to sufficiently recognize the lag period. That is, 39.83 days (revenue lag) minus 0 days (expense lead) equals 39.83 days of un-recovered cash flow.

Q. **Is there a similar expense lead time effect regarding depreciation and deferred income tax expense and that for expensing fuel from fuel inventory and distributions from materials and supplies inventory?**

A. Yes. I have argued that depreciation and deferred income tax expense each should be assigned a zero lead-time, in a lead-lag study, due to the rate base effects caused from recording accumulated depreciation and ADIT, respectively. Similarly, a zero expense lead-time is recognized for the actual expensing of fuel from fuel inventory and distributions expensed from materials and supplies inventory. That is the case because the lead time calculation assigned to fuel expense and to distributions from materials and supplies inventory is measured as the number of days from fuel and materials and

supplies being received and placed in inventory by the Company until the time the assets are paid for.

The time period that fuel and materials and supplies are in inventory has no impact on their lead-time when expensed and, also, while the inventory balances are earning a return in rate base they do not need cash working capital recognition. Therefore, when fuel and materials and supplies are expensed that event adds zero days of lead time. Further, the expensing of these inventories causes an offsetting decrease to rate base just like depreciation and deferred income tax expense do so through credits to accumulated depreciation and ADIT.

Hence, one can see that expensing depreciation, deferred income tax, fuel and materials and supplies inventory all have something in common. That is, each event should be assigned a zero lead time in a properly designed lead-lag study due to the offsetting reductions to rate base caused from recording accumulated depreciation, ADIT, and credits to fuel, and materials and supplies inventory.

Q. **Has there been disagreement about assigning zero lead times for fuel expensed from fuel inventory and distributions expensed from materials and supplies inventory?**

A. No. This is a generally accepted practice.

Q. **Is it consistent to assign zero additional lead days for fuel expensed from fuel inventory and distributions expensed from materials and supplies inventory, but not to assign zero lead days for depreciation and deferred income tax expense in the lead-lag study?**

A. No. Through recording of depreciation and deferred income tax expense, balances for accumulated depreciation and ADIT, respectively, are adjusted decreasing rate base. Similarly, through recording of fuel and materials and supplies distributions from inventory, balances for fuel and materials and supplies inventories, respectively, are adjusted decreasing rate base. There is no concept or principle of utility ratemaking that: (1) supports assigning zero lead days for the expensing of fuel and materials and supplies inventory, in the lead-lag study; yet, (2) supports not assigning zero lead days upon recording depreciation expense and deferred income tax expense.

Q. **Does the book, *Accounting for Public Utilities,* address the correct lead time to be used for depreciation and deferred income tax expense in the lead-lag study?**

A. Yes. The pages of § 5.04 of the book, *Accounting for Public Utilities*, explain that depreciation and deferred income tax expense should each be included in lead-lag studies with a zero lead time.

Q. **Do you believe it to be appropriate regulatory theory that the timing for the cash recovery of depreciation expense need not be included in the lead-lag study because the financial markets will adjust accordingly?**

A. No. I have found no regulatory principle, or financial or economic basis, suggesting the timing for the cash recovery of depreciation expense need not be included in the lead-lag study because the financial markets will adjust accordingly. The fact that the markets may adjust further supports my recommendations for handling depreciation expense in the lead-lag study. That is, if the Company is not provided cash working capital in rate base for that portion of test year depreciation expense not yet received through customers' revenues, it follows that OG&E will not be provided a reasonable opportunity to earn its authorized return on investment in utility assets. If OG&E does not earn a full return on its investment, the Company may not earn its authorized rate of return on equity either. Not earning a fair return on investment could cause the value of the Company's stock to fall unjustly.

Q. **Do you believe it appropriate that lead–lag studies should not include consideration for the cash return on shareholder equity?**

A. No. The position that lead-lag studies only include costs having current cash outlays was rebutted, generally, above in my testimony. Specifically, regarding this component, shareholders invested cash in the Company when they purchased shares of common equity. Even though that investment may have taken place in a previous period, it still should earn a fair return.

Investors should receive a return on the earnings held in cash by the customers. In fact, the investors' earned return is still invested in the operations of the utility until the Company receives the cash as customers pay their bills. When the common equity

earnings are not included in the cash working capital study with a zero lead time, the equity investor does not receive a return on those funds, invested as un-recovered earnings, between their realization through provision of service and when they are recovered through revenues.

Return on common equity is part of the cost of service included in utility rates. Since revenues are collected after a lag of about 39.83 days, the equity investors must wait for recovery of their cash return on investment until the end of that lag period. Therefore, investors must be compensated for that recovery lag from including the related investment in cash working capital.

Q. **Is the position valid that common equity earnings are excluded because when equity is returned to the Company through rates, funds in the possession of the Company are deemed in the possession of the owners of the Company?**

A. No. That argument is nonsensical. Clearly, from my testimony above, the cash working capital allowance for investors' equity earnings includes only that portion of their earnings for which the Company *has not yet received* through revenues. That is, only 10.9% (39.83 revenue lag days divided by 365 test year days equals 10.9%) of the test period net income, not yet received from customers even though electric service has been provided them, receives a cash working capital allowance here.

Q. **Does the book, *Accounting for Public Utilities,* address inclusion of net income in the lead-lag study?**

A. Yes. The pages of § 5.04 of the book, *Accounting for Public Utilities,* clearly explain that the common equity return to investors should be included in lead-lag studies with a zero lead time. The text explains from a theoretical standpoint, operating income is earned when service is provided, and the operating income is the property of the investors in the company when earned. This view recognizes the need for a cash working capital allowance to compensate investors for the lag in receipt of operating income.

Even with greater emphasis, the text stresses that when interest expense on long-term debt is included as a source of cash working capital, the common equity return to investors must be included as a cash working capital requirement. Historically, the

Company, and other Staff and party witnesses, has included interest expense on long-term debt as a source of cash working capital in the lead-lag study. The text concludes that if interest expense on long-term debt is a source of cash working capital in the lead-lag study, the common equity return to investors must be included too.

Q. **Why is it inconsistent to exclude equity earnings but not interest expense from the lead-lag study?**

A. Interest expense and equity earnings are each components of the cost of capital. The cost of capital is part of the cost of service and, thus, recovered through utility rates. Therefore, the lead and lag periods in the provision of service, and receipt of cash for that service, apply equally for each component of the cost of capital. However, if for some reason, the Commission should exclude the cash working capital needed for equity earnings, it must also exclude interest expense as a source of cash working capital.

Q. **Is the discussion of the Company's dividend policy relevant to whether the cash return on common equity should be included in the lead-lag study?**

A. No. The Company's dividend policy is not relevant to whether unrecovered equity earnings should be included in the lead-lag study. Correctly, OG&E's common dividend policy is not a consideration for the Company regarding its calculation of cash working capital. That is, OG&E's common dividend policy was not a consideration with respect to the lag in receipt of revenues for operating expenses, income taxes or any other component of the cost of service and, similarly, should not be a consideration regarding the lag in receipt of revenues for net income either.

Q. **Please explain why the Company's dividend policy is not relevant.**

A. The revenue lag-day period ends when cash revenues are received from customers. OG&E records that cash in the cash account. Subsequently, cash working capital consideration for the cash received from customers does not depend on whether those receipts are held by the Company as cash or provided to the shareholders as dividends. That is, decisions about how and when profits are distributed to the common equity owners of the Company are not relevant to performing the lead-lag study.

Q. **Do prior orders issued from the Commission, or other regulatory agencies, prohibit the Commission from adopting OG&E's cash working capital calculation here?**

A. No, based on my experience, ratemaking is a legislative process. Therefore, if the Commission is presented convincing evidence that supports changing its previous conclusions about ratemaking policy, prospectively, it can, and should do so. I believe that the Commission now has sufficient and competent evidence to adopt my recommendations for the correct treatment of depreciation expense, deferred income tax expense and net income in a lead-lag study.

SECTION IV: NET PENSION AND BENEFIT ASSET

Q. **Does the Company offer benefit plans for employees?**

A. Yes. Pursuant to eligibility requirements, OG&E offers defined benefit pension and restoration of retirement income plans, and postretirement medical and life insurance plans for employees.

Q. **Do these benefit plans create financial obligations for OG&E?**

A. Yes. The various benefit plans, for OG&E's employees, create specific financial obligations for the Company. As a result of these obligations, OG&E, pursuant to financial accounting requirements, must record a benefit obligations liability on its balance sheet.

Q. **Is the Company funding investments to meet financial obligations under the benefit plans?**

A. Yes. The Company maintains and funds an investment trust for its pension plan obligations. OG&E also funds an investment trust to meet its obligations for the postretirement medical and life insurance plans.

Q. **What is the effect on the Company's rate base due to the financial obligations and fund investments for the benefit plans?**

A. The liabilities and assets recorded on the Company's balance sheet to recognize benefit plan obligations and investments' status, when netted against each other, determine a net PBA, a regulatory asset. That net PBA should be recognized in the test period rate base.

Q. **What does the net PBA represent?**

A. The net PBA is a regulatory asset. The net PBA's balance equals the benefit obligations regulatory asset less the sum of: (1) the accrued benefit obligations (a liability account); and, (2) ADIT related to the net of the benefit obligations regulatory asset and the accrued benefit obligations liability.

Q. **What is the benefit obligations regulatory asset?**

A. The benefit obligations regulatory asset is comprised of pension and postretirement benefit costs that have been capitalized as a regulatory asset. At test year-end, the balance of the regulatory asset was $365.5 million.

The Company is allowed to capitalize these costs because: these costs have not yet been recognized as components of, nor recovered through utility revenues, as net periodic benefit cost expense; and, such costs, as expensed, are expected to be recovered through the Company's future utility rates. That is, the amount capitalized as a regulatory asset represents a net periodic benefit cost to be recognized as an expense in the Company's future income statements. In order to capitalize these costs, pursuant to financial accounting requirements, the Company had to demonstrate it historically recovered, and presently recovers, pension and postretirement benefit plan expenses through rates and no evidence exists indicating the regulatory treatment will change.

Q. **What is the accrued benefit obligations liability?**

A. The accrued benefit obligations liability represents the funded status of the Company's pension plan, restoration of retirement income plan and postretirement benefit plans. Put another way, it represents the difference between the value of the benefit plans' obligations and the fair value of pension and postretirement benefit plan investments. At

test year-end, the balances of the benefit plans' obligations and the fair value of pension and postretirement benefit plan assets were $783.7 million and $523.9 million, respectively. Therefore, at test year-end, the accrued benefit obligations liability balance was $259.8 million [$259.8 million = $783.7 million - $523.9 million].

Q. **What is the test year-end balance for the ADIT related to the net of the benefit obligations regulatory asset and the accrued benefit obligations liability?**

A. The test year-end balance for the ADIT related to the net of the benefit obligations regulatory asset and the accrued benefit obligations liability is $58.9 million.

Q. **What is the test year-end balance of the net PBA?**

A. The test year-end balance for the net PBA is $46.8 million [$46.8 million = ($365.5 million) – ($259.8 million + $58.9 million].

Q. **How should a commission determine a fair balance of the net PBA for inclusion in test period rate base?**

A. Similarly, as for other working capital components, regulatory commissions apply various combinations of several measurement techniques. Those techniques may include either averaging monthly balances or using a period ending balance.

As is the case for other working capital components, the net PBA balance allowed in rate base must assure the Company receives recognition of an investment amount commensurate with existing levels when new utility rates are established. Under certain circumstances, determining a representative amount for the net PBA can be difficult. The difficulty stems from the sensitivity of the plans' accrued benefit obligations and fair value of investment asset balances to financial markets, plan benefit changes and medical cost changes.

Q. **Do you recommend that the test year-end balance for the net PBA be placed in OG&E's rate base?**

A. Yes. The test year-end balance of $46.8 million for the net PBA should be placed in rate base for the test period. The difference between the year-end's and average balances for the net PBA does not warrant making an adjustment to the year-end balance.

Q. **Should the net PBA receive a full overall rate of return as is the case for other rate base components?**

A. Yes. Commissions generally recognize that each investor's dollar prudently invested in working capital, plant and other rate base items, should earn a full overall rate of return through customers' rates. As I explain above, that full return may be recovered through some combination of current and future rates. More specifically, I explained the return on investment may be recovered through: current rates if the investment is in the current rate base; or, it may be recovered through future rates when the utility is authorized to accrue financing costs, for capitalization, and inclusion in a subsequent test year's rate base.

Q. **If the Company were allowed to only recover through rates a cost of debt return on the net PBA, would that decision require an adjustment to the capital structure used to determine the rate of return applied to OG&E's remaining rate base?**

A. Yes. The Company should recover a full overall rate of return on the net PBA. However, if the Company is only allowed to recover a cost of debt return on the net PBA that decision requires Commission authorization for an adjustment to the capital structure used to determine the rate of return applied to OG&E's remaining rate base.

For example, above, I explain sometimes utility commissions only allow debt financing costs, on plant under construction, to be accrued and capitalized for recovery in future rates. Yet, even when only short or long-term debt costs are capitalized, the utility still earns, and recovers through customers' current or future rates, a full overall rate of return on each dollar prudently invested in plant. This is the case because, if only short or long-term debt costs are capitalized to construction costs, the remaining debt and equity financing costs incurred to fund the utility's other investments and operations are

allocated in greater proportions to rate base than otherwise. Simply stated, there is a larger allocation of equity financing costs to the remaining rate base.

Similarly, if the Commission only allowed a cost of debt return on the net PBA, the remaining debt and equity financing costs incurred to fund the utility's other investments and operations must be allocated in greater proportion to the remaining rate base. That is, investors are made whole for their financing costs, including the cost of equity, because a larger proportion of equity funding is allocated to other rate base components.

Q. **Is there another way to illustrate this concept?**

A. Yes. Let's assume the Company had a $100 rate base consisting of $90 in plant and $10 in the net PBA. Further, assume that the $100 rate base is funded with $50 debt and $50 equity financing. In other words, the Company, hypothetically, has a capital structure consisting of 50% debt and 50% equity. Now, let's examine two alternative treatments.

1. Cost of Debt Funding of Net PBA - Under this scenario, $10 of debt is assigned to fund 100%, or $10, of the net PBA for ratemaking purposes, leaving $40 of debt and $50 of equity assigned to the remaining rate base. Therefore, the remaining rate base is funded with 44.4% [44.4% = $40 ÷ ($40 + $50)] debt and 55.6% [55.6% = $50 ÷ ($40 + $50)] equity.
2. Full Rate of Return Funding of Net PBA - Under this scenario, $5 of debt and $5 of equity is assigned to fund the net PBA for ratemaking purposes, leaving $45 of debt and $45 of equity assigned to the remaining rate base. Therefore, the remaining rate base is funded with 50% debt and 50% equity, just like for the net PBA.

Under either of these scenarios, the total dollar return charged to the customers is the same. Still, under this example, sometimes witnesses would attempt to only assign a 50% equity level to the capital structure for the remaining rate base when advocating cost of debt financing for the net PBA. The flaw in that position is obvious. That reasoning requires the $10 of debt funding the net PBA to also be funding $10 of other rate base components. The Company cannot fund $20 of rate base with the same $10 of debt.

Q. **Has the Commission limited the return on a pension benefit asset to the cost of debt previously?**

A. Yes. One case in particular should be discussed here. A Commission order, Order No.564437 in Cause No. PUD 200800144 authorized for Public Service Company of Oklahoma ("PSO") only a cost of debt return on the pension benefit asset. Further, the Commission order did not then require an adjustment to the rate of return applied to the remaining rate base, as it should have done. That is, above, I explain allowing only a cost of debt return on the net PBA requires a greater allocation of equity to fund the remaining rate base.

Among other issues, PSO appealed the Commission's decision to only authorize a cost of debt return on the pension benefit asset to an Oklahoma appellate court. The appellate court upheld the Commission's decision to only authorize a cost of debt return on the pension benefit asset.[7] However, the appellate court did not address whether that treatment requires a greater allocation of equity to fund the remaining rate base.

Q. **Please explain the relevance of the appellate court ruling to your recommendations here?**

A. I have recommended that the Commission should allow a full rate of return for the Company's investment in the net PBA. However, I did not dispute whether the Commission could assign only a cost of debt return for the net PBA, as long as it made the related required adjustment to the rate of return applied to the remaining rate base. Therefore, because the appellate court did not address whether the treatment of assigning only a cost of debt return for the net PBA requires a greater allocation of equity to fund the remaining rate base, the decision is not fully relevant here.

Q. **What is the impact to the Company's earnings from allowing a cost of debt return on the net benefit asset instead of an overall rate of return?**

A. In Exhibit JMP-2, I have calculated an estimate illustrating the loss in the Company's earnings due to only allowing a cost of debt return on the net PBA without making the related capital structure adjustment discussed herein. The Commission can see from that

[7] In the Court of Civil Appeals of the State of Oklahoma, Division III, Case No. 106,778.

exhibit the earnings deficiency caused by only allowing a cost of debt return, instead of the overall rate of return, on the net PBA is $1,846,740.

Q. **Should the Company's return on the net PBA depend on whether pension and postretirement benefit plan funding contributions are mandatory or discretionary?**

A. No. The dollar amount of contributions to the pension and postretirement benefit plans should not arbitrarily have a bearing on whether the Company receives a cost of debt return or full rate of return on the net PBA. OG&E should receive the overall rate of return on rate base investments unless it can be shown the investment is either for a non-utility purpose, unreasonable or imprudent.

Q. **What factor determines whether contributions to the Company's pension and postretirement benefit plans are mandatory or discretionary?**

A. Any reference to whether a contribution is mandatory or discretionary relates to the provisions of the Employee Retirement Income Security Act of 1974 ("ERISA"). The ERISA of 1974 specifies minimum regulatory funding requirements for pension plans. Contributions above the minimum amount are discretionary. Discretionary contributions are not prohibited nor discouraged by the ERISA of 1974.

Q. **Is the Company acting unreasonably or imprudently when making discretionary contributions?**

A. No. The Company's objective in making contributions to the benefit plans is to help ensure that the pension plan maintains an adequate funded status. That means contributions, whether mandatory or discretionary, are intended to provide not only for employee benefits attributed to service to date, but also for services expected to be earned by employees in the future.

Q. **Why is the Company making discretionary contributions to the benefit plans?**

A. The funded status of the Company's pension and postretirement benefit plans are not solely based on the amount of funding. The funded status is also dependent on the fair

market value of plan assets and the discount rate used to determine the present value of benefit obligations.

If market returns are high, as they have been recently, the fair value of plan assets tends to be greater. When the discount rate, based on high-grade corporate bond interest rates, are lower, as they have been recently, the present value of benefit obligations increase. The Commission can understand that discretionary contributions help mitigate risks in the financial markets that could potentially negatively affect the funded status of the benefit plans. Thus, it is reasonable for the Company to maintain a favorable funded status of the benefit plans as a hedge against significant declines in fund asset values or increases in the present value of benefit plan obligations.

Further, when the Company makes contributions above the mandatory level, those contributions, over time, generate larger expected returns on plan assets, thus, lowering future contributions and net periodic benefit costs charged to customers. A decrease in the net periodic benefit cost helps keep customer rates lower than otherwise.

SECTION V: MATERIALS AND SUPPLIES INVENTORY

Q. **Are materials and supplies inventories a component of rate base?**

A. Yes. The investment in materials and supplies must be included in test period rate base. As is the case for cash working capital, it must be measured with care to assure the Company receives recognition of an investment level commensurate with inventory requirements when new utility rates are established.

Q. **How should a commission determine a fair balance of materials and supplies inventory for test period rate base?**

A. As discussed above, regulatory commissions apply some combination of several measurement techniques to determine working capital requirements like materials and supplies inventory. Those techniques include averaging historic month-end test year balances; using a historic test year-end balance; averaging historic month-end test year and month-end post test year balances; using a historic balance at some month-end after the end of the test year; and, projecting or forecasting balances. A commission may use various combinations and variations of these techniques. But, the goal should always be

to select a method that reasonably represents expected levels of materials and supplies investments during the period the new rates will be charged.

Q. **When would one measure materials and supplies inventory using average balances?**

A. Sometimes materials and supplies balances tend to fluctuate through any given twelve month period. When working capital balances vary overtime, an average of balances may provide a better estimate of the on-going investment for those respective assets. However, one must keep in mind, as I explain earlier herein, it may be necessary to extend the averaging beyond test year end to capture levels of investment more closely in line with prospective requirements. That is, even though monthly balances of materials and supplies may vary up and down somewhat from month to month, the general trend could be one of increasing amounts. In certain cases, it may be appropriate to forecast or project a balance for materials and supplies when such investment is consistently increasing.

Q. **When would it be appropriate to measure materials and supplies using period ending balances?**

A. Sometimes materials and supplies investments consistently increase overtime. If working capital assets, such as materials and supplies inventory, are increasing, then it may be appropriate to measure that working capital component at test year end. As for averaging materials and supplies balances, it may be necessary to measure the period ending balance at a month-end beyond the test year, or use a forecast, to capture levels of investment more closely in line with prospective requirements.

Q. **What level of materials and supplies inventory do you propose for test period rate base?**

A. I propose that OG&E be authorized to include an amount of $83,919,464 in test period rate base for materials and supplies inventory. That amount of inventory is the forecasted balance for materials and supplies as of December 31, 2011. In Exhibit JMP-3, attached to my testimony, I include a calculation explaining the derivation of that balance.

Q. **What, then, is the adjustment to test period rate base?**

A. The adjustment to materials and supplies inventory is shown as Rate Base Adjustment No. 13. Specifically, the adjustment increases the test period's year-ending balance of inventory of $77,096,658 by $6,822,806. Therefore, the pro forma level of materials and supplies inventory is $83,919,464, the forecasted balance for December 31, 2011.

Q. **Why do you propose to use a forecasted balance as of December 31, 2011?**

A. In Exhibit JMP-3 attached to my testimony, I provide an analysis of materials and supplies inventory. The Commission can see from that exhibit the Company's average materials and supplies inventory has approximately doubled from December 31, 2003 through December 31, 2010. Further, the increase in inventory has steadily increased over this period. The annual increase in the average inventory balance has ranged from 3.8% to 16.0%. I believe this forecasted balance will more closely align with the prospective materials and supplies needs of the Company in the future.

Q. **Has the Commission allowed post test year balances of materials and supplies inventory in rate base before?**

A. Yes. Commission Order No. 516261 in Cause No. PUD 200500151 authorized the Company a materials and supplies inventory in rate base based on a 13-month average of actual inventory levels up through a period ending 6 months after test year-end.

Q. **Why has the investment in materials and supplies inventory increased steadily over recent years?**

A. The increase in materials and supplies inventory is due to price increases, increases in the required quantity of inventories due to utility plant construction and acquisitions, and changes in the mix of assets in inventory due to changing technology and new efficiency programs.

Q. **How did you forecast the amount of materials and supplies inventory as of December 31, 2011?**

A. I multiplied the actual test year-end balance of inventory at December 31, 2010 by the average of the annual increases in the average balance of materials and supplies inventory between 2008 and 2010. The calculation provided in Exhibit JMP-3 is $77,096,658 times 1.0885 equals $83,919,464 using an average annual growth rate of 8.85%.

Q. **If the Commission chooses not to adopt a forecasted balance for rate base, what do you recommend?**

A. I recommend the Commission include in test period rate base either: the actual 13-month average of month-ending balances for 2011; or, the year-ending balance at December 31, 2011 of materials and supplies inventory, whichever is greater.

Q. **What do you estimate could be the lost earnings due to increases in the value of materials and supplies inventory?**

A. In Exhibit JMP-3, I have calculated an estimate for illustrating the loss in the Company's earnings due to increasing values of the materials and supplies inventory. In that exhibit, I have compared the actual test year's year-ending inventory balance to forecasted 13-month average inventory balances for 2012 and 2013. The reason I selected 2012 and 2013 for the comparison is that I expect the rates established herein will be in effect for at least those two years.

The calculation shows the potential earnings foregone due to forecasted increases in materials and supplies inventory is $1,004,296 and $1,621,537 for 2012 and 2013, respectively. This calculation assumes the same 8.85% growth rate in inventory balances used in forecasting the December 31, 2011 balance.

SECTION VI: COAL INVENTORY

Q. **How should a commission determine a fair balance of coal inventory for test period rate base?**

A. Like materials and supplies inventory, regulatory commissions apply various combinations of several measurement techniques to determine test period coal inventory

requirements. Those techniques may include averaging monthly balances; using a period ending balance; and, projecting or forecasting balances.

Often when a commission either averages balances or uses a period ending balance for plant, it uses the same method for coal and other fuel inventories. With respect to coal inventory, it is also common for commissions to determine the balance in rate base pursuant to the amount of coal burned over a specified time period. The latter method can be referred to as the "burn level" method.

As is the case for other working capital components, coal inventory must be measured with care to assure the Company receives recognition for an investment level commensurate with existing inventory when new utility rates are established. Further, because coal usage and coal inventory levels can vary over time due to coal purchase and delivery contracts, climate, planned unit maintenance, and unplanned unit outages, a commission should not arbitrarily disallow a return on actual inventory levels which exceed a specified "burn level" due to reasonableness or imprudence.

Q. **How are coal burn level requirements determined?**

A. Over the years, I have seen the amount of coal inventory placed in rate base determined based on the amount of coal burned over periods of 120 days, 90 days, 75 days and 60 days. The burn level is usually based on either average day usage, peak day usage or some target level of usage other than the average and peak day level. Usually, a target level of inventory is based on informed reasoning.

Generally, as the period for which the burn level is determined declines in number of days, it may be more appropriate to establish coal inventory requirements based on peak day burn levels or, even better, on a reasonable target amount. It is important not to set the burn level too low putting the utility at risk for running out of coal inventory or needing to use more expensive gas generation and power purchases.

Q. **What do you mean by informed reasoning?**

A. Informed reasoning involves determining an economically and operationally optimal level of inventory from taking into account the various risks and costs to the utility from not maintaining that level. For example, the analysis may take into consideration the

relationship between the balance of coal inventory maintained and the total generation costs for the utility. Further, the analysis should consider the relationship between the coal inventory and service reliability.

Q. **Will you please illustrate the calculation of coal inventory requirements based on a 60-day peak burn level?**

A. Let's assume the highest tonnage of coal burned in any one day in a given year was 35,000 tons. Then, coal inventory requirements based on a 60-day peak burn level is calculated simply as the product of 35,000 tons and 60 days, thus 2,100,000 tons. The amount of coal inventory in rate base would be the 2,100,000 tons valued at a per tonnage price.

Q. **Will you please illustrate the calculation of coal inventory requirements based on a 60-day average burn level?**

A. Let's assume the average tonnage of coal burned per day in a given year was 25,000 tons. Then, coal inventory requirements based on a 60-day average burn level is calculated simply as the product of 25,000 tons and 60 days, thus 1,500,000 tons. The amount of coal inventory in rate base would be the 1,500,000 tons valued at a per tonnage price.

Q. **Why do commissions sometimes base coal inventory requirements, for rate making purposes, on "burn levels"?**

A. Regulatory commissions establish coal inventory requirements, for ratemaking purposes, based on "burn levels" in order to discourage utility company investment in excessive inventory. Therefore, such policy minimizes rate base investment and, thus, rates too. That is, as an example, a commission may conclude that a sufficient level of coal may be based on average or peak day burns and that any amounts above that level should not be in rate base.

The Commission must be mindful that such a finding establishes and implements prudence standards. However, such a standard, even though it may be similar to standards used in other regulatory jurisdictions, sometimes can seem to be rather arbitrary. Setting an arbitrary standard could work against the public interest. That is,

the prudent utility manager may find herself confronted with the choice of maintaining, on average, an inventory level based on the "burn level" allowed in rate base or, perhaps, a higher amount she deems necessary to assure a reliable and cost efficient supply of coal. If a higher amount is determined necessary by management, it must be willing to forgo a return on that additional prudent investment if undertaken.

Q. **Is it possible for coal inventories to become larger than planned for because of uncontrollable events?**

A. Yes. To minimize costs and assure a dependable coal supply, a utility needs to enter purchase and transportation contracts in advance of their knowing exactly how much fuel will be needed. That is, coal usage and coal inventory levels can vary over time due to: uncontrollable effects such as weather; unplanned unit outages; extended unit outages or, even planned unit maintenance.

Q. **Should a commission consider the impact of uncontrollable events when deciding on whether to base inventory levels on average or peak day burn requirements, or some other alternative method?**

A. Yes. If coal inventories are larger than normal due to events beyond the control of management, one should not simply deem the abnormal level of coal inventory imprudent.

That is, uncontrollable events, in conjunction with prudently negotiated purchase and transportation contracts, may cause the coal inventory to be larger for a period of time. Because such events are uncontrollable, and do occur occasionally, a commission should consider allowing for a return on the additional coal inventory caused by the event(s), especially when such event(s) are prudently managed by the utility's management to mitigate damages.

Remember, the objective under the rate base/rate of return approach is to set the revenue requirement to allow the utility a fair opportunity to recover, through its rates, all prudently incurred expenses and a fair return on the utility's prudent investment. When coal inventories are larger due to uncontrollable events, the additional inventory caused

by those events was not caused from imprudent management decisions and should be considered for inclusion in rate base to earn its required return.

Q. **How is the Company's allowed inventory for ratemaking purposes calculated when based on 60-day peak or average burns?**

A. The peak burn level of coal during the test year of 33,060 tons occurred on July 19, 2010. A 60-day burn level based on that peak burn is 1,983,600 tons [33,060 tons * 60 days = 1,983,600 tons].

The total amount of coal burned during the test year was 8,517,566 tons. If one divides that amount by 365 days, the average daily burn for 2010 is 23,336 tons. A 60-day burn level based on that average burn is 1,400,160 tons [23,336 tons * 60 days = 1,400,160 tons].

Q. **What was the actual average and year-end coal tonnage in inventory for the test period?**

A. The actual average of the 13-month ending balances of coal inventory for 2010 was 3,368,290 tons. The year-end balance of coal inventory on December 31, 2010 was 3,768,488 tons. When comparing either the test period's actual average or year-end amount of coal inventory to the inventory requirements based on 60-day average or peak burn levels, the Commission can see the amount of inventory investment at stake here is substantial.

Q. **Why was OG&E's actual average and year-end coal inventory for the test period greater than either the 60-day peak or average burn levels?**

A. Prior to and during the test year, OG&E experienced a number of events that impacted its coal units. In 2009, OG&E experienced several outage related events that reduced coal-fired generation and caused increased coal pile inventory. Specifically, Muskogee Unit 5 experienced a power cable fault, which took the unit off for approximately two weeks, and Sooner Unit 2 experienced an economizer header tube leak which caused the unit to run at a decreased load for two weeks. This combined four week period of reduced coal-

fired generation along with routine planned outages contributed to the increased coal inventory going into the 2010 test year.

In 2010, the Company continued to have planned and unplanned outage events that attributed to the greater than average level of the coal inventory. Muskogee Unit 4 had an unplanned load reduction due to condenser tube leaks and eventual repair. Due to this unplanned outage Unit 4 was either de-rated or offline for approximately three months. Muskogee Unit 5 required boiler tube leak and mill maintenance and repairs that took the unit off for approximately a month. Muskogee Unit 6 experienced a planned overhaul that extended one week past the Company's original planned duration, and an unplanned outage which lasted one week. Sooner Unit 1 was offline 10 days due to a planned and unplanned outage. Sooner Unit 2 required economizer header repairs that lasted six weeks and were a carryover from the 2009 tube leak event. Sooner Unit 2 also had a planned overhaul that lasted nearly eight weeks. In addition to the larger outages listed, the coal plants also experienced several outages and extensions of outages, smaller in nature that attributed to the larger coal inventory, including, but not limited to: mill repair, tube leaks, pack pressure, and economizer deratings.

Q. **Were there any additional factors that led to OG&E's actual average and year-end coal inventory for the test period being greater than either the 60-day peak or average burn levels?**

A. Yes. In 2009, operational impacts, due to the Southwest Power Pool Energy Imbalance Services ("SPP EIS") Market, also played a role in the Company's increased inventory. For example, the inventory balances increased during 2009 due to low natural gas prices and the entrance of Nebraska utilities into the SPP EIS Market providing new, lower cost coal-fired generation alternatives. This combined with OG&E experiencing increased coal transportation rates, leading to higher delivered coal costs, resulted in the Company's coal units no longer assuming the position as the lowest cost resource in the market. This led to OG&E's coal units being backed down during off-peak hours and, thus, a resulting unexpected drop in the Company's coal burn.

Q. **Please explain the steps the Company has taken, and plans to take, to manage the coal inventory surplus?**

A. In order to reduce coal pile inventory, the Company reduced its contractual coal take levels for 2010, 2011 and 2012. In 2010, the Company released 150,000 tons of contracted tonnage back to one of its suppliers. In 2011, the Company released another 350,000 tons of contracted tonnage back to one of its suppliers. Additionally in 2011, the Company made the decision not to purchase the last 1,200,000 tons called for in its forecasted plan. In 2012, the Company plans to purchase less coal than is called for in its forecasted plan.

Q. **Has the Company management acted prudently in addressing the coal inventory situation?**

A. Yes. I believe the Company has taken the necessary steps to mitigate the damages caused by the uncontrollable events described above.

Q. **What level of coal inventory do you propose for test period rate base?**

A. I propose that OG&E be authorized to include $66,903,408 in test period rate base for coal inventory. That amount of inventory represents a coal inventory level of 1,980,000 tons priced at $33.79 per ton, the weighted-average cost of coal in inventory at December 31, 2010. That level of inventory is slightly less than the test period's 60-day peak burn level of 1,983,600, but is based on a target level of inventory proposed by OG&E in a previous rate case.[8]

Q. **What, then, is the adjustment to test period rate base?**

A. The adjustment to coal inventory is shown as Rate Base Adjustment No. 4. Specifically, the adjustment decreases the test period's year-ending balance of inventory of

[8] Although Order No. 569281 of Cause No. PUD 200800398 is silent on the amount of coal inventory allowed in rate base, OG&E witness Donald R. Rowlett proposed a coal inventory level based on 1,980,000 tons. Staff witness Scott Grass and the Attorney General's witness Roya Soltani each agreed with the Company's proposal to allow 1,980,000 tons in rate base. That amount of coal inventory represented a 60-day requirement based on a "full load" burn of 33,000 tons per day. The Company established the "full load" burn day of 33,000 tons based on typical summer coal burn levels when all five coal production units are available to meet summer system-wide loads. Also, a burn level of approximately 1,980,000 tons was authorized by the Commission for OG&E through Order No. 516,261 in Cause No. PUD 200500151.

$127,335,802 by $61,401,802. Therefore, the pro forma level of coal inventory is $65,934,000, based on a coal inventory level of 1,980,000 tons priced at the weighted-average cost of coal in inventory at December 31, 2010.

Q. **Why do you propose for the Commission to authorize a test period inventory level representing a 60-day requirement, based on a "full load" burn of 33,000 tons per day, instead of an inventory amount based on either the actual test year dollar average of the 13-month ending balances or the test year-ending balance?**

A. Above, I explain the factors causing the actual coal inventory, during the test year, to be greater than normal were beyond the control of management. Further, I explain the efforts taken by the management to control the situation. Therefore, the amount by which the actual test year coal inventory exceeds levels based on coal burns should not be deemed an imprudent investment.

However, even though the test period's actual amount of coal inventory investment is prudent, the Company believes that the steps it has been taking to decrease its coal inventory should result in an inventory amount consistent with the 60-day burn level by the end of 2011. Because the coal inventory investment by year-end should be down to a normal level, the Company believes it is equitable to base its new electric rates on that decreased amount of inventory.

Q. **What is the impact to the Company's earnings from basing its allowance for coal inventory on a 60-day burn level amount?**

A. In Exhibit JMP-4, I have calculated estimates illustrating the potential annual earnings impact to the Company due to its not seeking, and being granted, an inventory amount based on either the actual test year average or year-ending balance.

As shown in the exhibit, the dollar amount of inventory, based on the Company's target level of tonnage under normal circumstances, of 1,980,000 tons, is $65,934,000. Again, that is the amount the Company is asking to include in the test period rate base. When comparing the Company's target level of $65,934,000to the test year average inventory of $105,238,425, one finds a potential rate base adjustment of $39,304,425 [$39,304,425 = $105,238,425 - $65,934,000]. Finally, in reviewing the calculation in Exhibit JMP-4,

one finds the annual earnings foregone due to a rate base adjustment of this magnitude is $2,968,700. Similarly, when comparing the Company's target level of $65,934,000 to the test year-end inventory of $127,335,802, one finds a potential rate base adjustment of $61,401,802 [$61,401,802 = $127,335,802 - $65,934,000]. A rate base adjustment of this amount results in an annual earnings decrease of 4,679,942.

Q. **Should the Commission base a decision to decrease the allowable coal inventory in rate base below actual test year amounts on prudence?**

A. Certainly not. I do not believe the Company should be confronted with an annual adjustment of this magnitude based on imprudence. The basis for including the Company's target inventory level of $65,934,000 in rate base should be that OG&E believes by the end of 2011 it will have decreased its on-going coal inventory, on average, to approximately 1,980,000 tons of coal.

Q. **Do the Company's analyses demonstrate it can achieve the target level by the end of 2011?**

A. Yes. The Company has been diligent in managing and responding to the events causing the substantial increase in its coal inventory over the last three years. As a result, OG&E believes the on-going coal inventory, on average, can reach the target level of 1,980,000 tons by the end of 2011.

Q. **Do you have any additional comments concerning the treatment for coal inventory in this rate case?**

A. Yes. I have emphasized throughout my testimony the importance of setting electric rates to recover those costs to be incurred during the periods rates will be charged customers. If the Commission elects to not consider cost levels beyond the historic test period in achieving that objective, I believe it should allow the test period level of coal inventory to be based on the test year average of $105,238,425. That is, as demonstrated herein, the larger than normal test year level of coal inventory was caused by factors beyond the control of management. Therefore, an adjustment to decrease the test period level of coal

inventory below the test year average of $105,238,425 is not justified by a finding of imprudence. The Company's management addressed the problem prudently.

Q. **If the Commission does not allow for the increases in the balance of materials and supplies inventory through December 2011, is it fair to do so for decreases in the coal inventory?**

A. No. I have recommended for the Commission to include a forecasted balance, as of December 31, 2011, of materials and supplies in rate base. Alternatively, I have suggested the Commission could include in rate base either the 2011 average or year-ending balance of materials and supplies, whichever is greater. Therefore, to be consistent, if the coal inventory is based on decreased levels existing at the end of 2011, the increased levels of materials and supplies inventory in December 2011 should also be included in pro forma rate base.

SECTION VII: NATURAL GAS INVENTORY

Q. **What adjustment are you proposing to the balance of natural gas inventory included in rate base?**

A. I propose to include the 13-month average, of month-ending test year balances, as the pro forma test period level of natural gas inventory in rate base. The adjustment to natural gas inventory is shown as Rate Base Adjustment No. 5. Specifically, the adjustment increases the test period's year-end balance of natural gas inventory of $5,563,773 by $2,806,977. Therefore, the pro forma level of natural gas inventory is $8,370,750.

Q. **Why do you propose the average balance instead of the year-end balance?**

A. There was a great deal of variation in the monthly volumes and weighted-average price of the natural gas inventory during the test year. Therefore, the natural gas inventory should be valued based on an average of monthly balances.

Q. **In a recent rate case was the natural gas inventory allowed for the Company based on volumes of 2.2 million MMBtu?**

A. Yes. In Commission Order No. 569281 in Cause No. PUD 200800398, the Company was authorized a test period balance of 2.2 million MMBtu of natural gas inventory. If OG&E proposed that level in the current proceeding, based on the monthly weighted-average test period cost of gas in inventory of $4.36 per MMBtu, the Company's request for natural gas inventory would be $9,597,038.

Q. **Why is the Company not seeking to include 2.2 million MMBtu of natural gas inventory in this case?**

A. The test period's average monthly volumes, and most monthly balances of natural gas volumes during 2009 and 2010, were less than 2.2 million MMBtu of natural gas inventory. Therefore, even though the Company still supports, as reasonable, a level of inventory based on 2.2 million MMBtu of natural gas, we believe the recent actual inventory levels do not fully endorse it.

SECTION VIII: OTHER WORKING CAPITAL

Regulatory Assets and Liabilities

Q. **What adjustments are you proposing to the balance of regulatory assets and liabilities included in rate base?**

A. After making adjustments to eliminate or reclassify certain items, I propose to include the remaining test year-ending balances for regulatory assets and liabilities in the pro forma test period rate base.

In Exhibit JMP-5, attached to my testimony, I include an itemization of the regulatory assets and liabilities used to increase and decrease pro forma rate base, respectively. The largest adjustment is to reclassify the benefit obligations regulatory asset of $365.5 million to the net PBA as discussed above. The remaining adjustments are explained in the footnotes of Exhibit JMP-5.

The combined adjustment to the regulatory assets and liabilities is shown as Rate Base Adjustment No. 13. Specifically, the adjustment decreases the test period's year-end

balance of regulatory assets of $489.8 million by $381.6 million. Therefore, the pro forma level of regulatory assets is $108.2 million.

Fuel Oil Inventory

Q. **What adjustment are you proposing to the balance of fuel oil inventory included in rate base?**

A. I propose to include the 13-month average, of month-ending test year volumes, of 849,230 gallons of fuel oil, priced at $3.15 per gallon for determining the pro forma test period level of fuel oil inventory in rate base. The adjustment to fuel oil inventory is shown as Rate Base Adjustment No. 4. Specifically, the adjustment increases the test period's year-end balance of $1,987,899 by $687,176. Therefore, the pro forma level of fuel oil inventory is $2,675,075.

Q. **Why have you priced the fuel oil inventory at $3.15 per gallon?**

A. The Company typically purchases fuel oil during the last quarter of the calendar year. Therefore, because prices have been increasing and the Company has been quoted a delivered price for no. 2 fuel oil of $3.15 per gallon for delivery to Sooner Power Plant for October 2011, I believed it reasonable to value the fuel oil inventory at that price.

Prepayments

Q. **What are prepayments?**

A. Prepayments represent the amount of funds expended for cost(s) in period(s) prior to those for which the cost(s) apply. Examples of prepayments include prepaid insurance, rent and demand fees. Such prepayments are initially recorded as an asset and then either amortized, or expensed as used over time.

Q. **Why are prepayments included in rate base?**

A. Prepayments represent an investment of funds in utility operations. As an investment of funds, prepayments should be included in rate base to earn a return for investors. Prepayments can be included in rate base as a utility asset or accounted for in the lead-lag

study used to determine cash working capital. For this rate case, prepayments have been included in rate base as a working capital asset.

Q. **What adjustment are you proposing to the year-end balance of prepayments?**

A. I propose to include the 13-month average, of month-ending test year balances, as the pro forma test period level for prepayments in rate base. The adjustment to prepayments is shown as Rate Base Adjustment No. 15. Specifically, the adjustment decreases the test period's year-end balance of prepayments of $7,551,507 by $455,616. Therefore, the pro forma level of prepayments is $7,095,891.

Customer Deposits

Q. **What are customer deposits?**

A. Customer deposits represent funds received from utility customers as security against potential losses from unpaid bills. As such, customer deposits represent a liability to return the funds at some future time. While the utility holds the deposits, the customer receives interest accruals and the utility may use the funds to support rate base investments.

Q. **What ratemaking treatment do you recommend for customer deposits?**

A. Customer deposits represent a source of capital for the Company. There are two rate making alternatives available for the deposits. Either of the alternatives is generally accepted as theoretically sound. One alternative is to include the deposits in the capital structure with the appropriate interest rate. Another is to subtract the balance of deposits from rate base and include the interest as an expense in the cost of service.

The Company proposes to subtract the balance of deposits from rate base and include the interest as an expense in the cost of service. Selecting this treatment allows the Company to simplify its capital structure by limiting it to just long-term debt and common equity. Further, using this ratemaking treatment allows the Company to treat all customer-supplied capital as rate base reductions.

Q. **What amount of customer deposits should be subtracted from rate base?**

A. I am proposing that the year-end balance for customer deposits of $63,315,986 be subtracted from rate base. The monthly test year balances for the liability did not vary enough to require averaging.

Q. **Does that conclude your testimony?**

A. Yes, it does.

Oklahoma Gas and Electric Company
Cash Working Capital
Earnings Impact Analysis
Test Year Ending December 31, 2010

A	B	C	D	E	F	G	H	I	J
Component Analyzed	Note	OG&E Pro Forma	Revenue Lag Days	Revenue Lag Days ÷ 365 Days	Cash Working Capital Required Col. C * Col. E	Gross of Tax ROR	Pro Forma Annual Revenue Lost	1 Minus Composite Tax Rate	Pro Forma Annual Earnings Lost
Depreciation and Amortization	1	205,244,947	39.83	0.109	$ 22,397,003	0.126	$ 2,832,168	0.612	$ 1,734,445
Deferred Income Tax Expense	1	67,103,991	39.83	0.109	7,322,608	0.126	925,966	0.612	567,070
Investment Tax Credit Amortization	1	(3,726,468)	39.83	0.109	(406,644)	0.126	(51,421)	0.612	(31,491)
Net Income	1	202,884,273.00	39.83	0.109	22,139,399	0.126	2,799,593	0.612	1,714,496
Total		$ 471,506,743			$ 51,452,366		$ 6,506,306		$ 3,984,520

Note 1 - Shedule E-1 of OGE MFR

Exhibit JMP-1

Oklahoma Gas and Electric Company
Net Pension and Benefit Asset
Earnings Impact Analysis
Test Year Ending December 2010

A Net Pension and Benefit Asset	B Total Company Test Year Amount Gross of Tax TYE 12/31/2010	C Total Company Test Year Amount ADIT TYE 12/31/2010	D Total Company Test Year Amount Net of ADIT TYE 12/31/2010	E Gross of Tax Cost of Debt	F Estimated Revenue Cost of Debt Method Col. D * Col. E	G Gross of Tax ROR	H Estimated Revenue ROR Method Col. D * Col. G	I Estimated Annual Revenue Lost Col. H - Col. F	J 1 Minus Composite Tax Rate	K Estimated Annual Earnings Lost Col. I* Col. J
Test Year End Balance in Rate Base **(Note 1)**	$ 105,713,983	$ 58,927,430	$ 46,786,553	0.0620	$ 2,900,766	0.126	$ 5,916,300	$ 3,015,534	0.612	$ 1,846,740

Note 1	**TYE 12/31/2010**
Benefit Obligations Regulatory Asset	$ 365,487,216
Accrued Benefit Obligations Liability	259,773,233
Net Pension and Benefit Asset	$ 105,713,983

Exhibit JMP-2

Oklahoma Gas and Electric Company
Materials and Supplies Inventory
Earnings Impact Analysis
Test Year Ending December 31, 2010

A	B	C	D	E	F	G	H	I
M&S Inventory Method	Note	OG&E Test Year End Inventory	OG&E Estimated Inventory	Estimated Growth in Inventory	Gross of Tax ROR	Estimated Revenue Lost	1 Minus Composite Tax Rate	Estimated Earnings Lost
Estimated Year End Balance 12/31/2011	1	$ 77,096,658	$ 83,919,464	$ 6,822,806	0.126	$ 862,764	0.612	$ 528,365
Estimate Thirteen Month Average 2012	2	$ 77,096,658	90,065,190	12,968,532	0.126	1,639,910	0.612	$ 1,004,296
Estimate Thirteen Month Average 2013	3	$ 77,096,658	98,035,670	20,939,012	0.126	2,647,801	0.612	$ 1,621,537

	2003	2004	2005	2006	2007	2008	2009	2010
Thirteen Month Average Inventory	$ 38,880,945	$ 45,083,181	$ 51,591,562	$ 53,547,871	$ 59,782,655	$ 64,237,622	$ 72,389,743	$ 76,015,590
Annual Percentage Increase		15.95%	14.44%	3.79%	11.64%	7.45%	12.69%	5.01%
Two Year Average Increase 2008 -2010								8.85%
Three Year Average Increase 2007 -2010								8.38%
Four Year Average Increase 2006 -2010								9.20%
Five Year Average Increase 2005 -2010								8.12%
Six Year Average Increase 2004 -2010								9.17%
Seven Year Average Increase 2003 -2010								10.14%

		Total Company 2010 Actual	2 Year Ave Rate	Estimate
Estimated Year End Balance 12/31/2011	1	$ 77,096,658	1.0885	$ 83,919,464
Estimate Thirteen Month Average 2012	2	$ 76,015,590	1.1848	$ 90,065,190
Estimate Thirteen Month Average 2013	3	$ 76,015,590	1.2897	$ 98,035,670

Exhibit JMP-3

Oklahoma Gas and Electric Company
Coal Inventory
Earnings Impact Analysis
Test Year Ending December 2010

A	B	C	D	E	F	G	H	I
Inventory Method	Note	OG&E 2010 Average Coal Inventory	OG&E 60 Day Burn Coal Inventory	Coal Inventory Excluded	Gross of Tax ROR	Estimated Annual Revenue Lost	1 Minus Composite Tax Rate	Estimated Annual Earnings Lost
2010 Thirteen Month Average Inventory	1	$ 105,238,425	$ 66,903,408	$ 38,335,017	0.126	$ 4,847,578	0.612	$ 2,968,700
2010 Year-Ending Inventory		$ 127,335,803	$ 66,903,408	$ 60,432,395	0.126	$ 7,641,858	0.612	$ 4,679,942

	Tons	Weighted-Average $/Ton Inventory 12/31/10	Total Company Pro Forma Inventory
Note 1			
2010 Thirteen Month Average Inventory			$ 105,238,425
2010 Year-Ending Inventory			$ 127,335,803
OGE Cause No. PUD 200800398			
60-day Estimate of 1,980,000 tons	1,980,000	$ 33.79	$ 66,903,408

Exhibit JMP-4

Exhibit JMP-5

Oklahoma Gas and Electric Company
Regulatory Assets and Regulatory Liabilities
Test Year Ending December 2010

A	B	C	D	
OTHER REGULATORY ASSETS	**Balance 12/31/2010 $000s**	**Adjustment $000s**	**Adjusted Test Year Balance $000s**	**Note**
OCC Assessment Fee	$ 709		$ 709	
OK Deferred Storms Expense	28,518	$ (28,518)	-	**1**
AR Deferred Storms Expense	105	(105)	-	**2**
OK Deferred Pension Expenses	10,846		10,846	
AR Deferred Pension Expenses	2,703	(2,703)	-	**2**
Wind RFP OCC Staff Evaluator	434		434	
OU Spirit Attorney General Independent Evaluator	32		32	
Redbud OCC Staff Expert	18	(18)	-	**3**
Income Taxes Recoverable in Future Rates	50,674		50,674	
SFAS 158	365,487	(365,487)	-	**4**
Red Rock Post Abandonment	7,154		7,154	
AFUDC Debt Normalized since 1978 -Tax Recoverable in Future Rates	8,710		8,710	**1**
Smart Grid O&M	2,393	(2,393)	-	**1**
Smart Grid Stranded Costs	11,763	17,686	29,449	
Smart Grid Web Portal	29	(29)	-	**1**
Crossroads Wind Independent Evaluator	192		192	
Red Rock Attorney General Witness	74	(74)	-	**3**
	$ 489,841	$ (381,641)	$ 108,200	

OTHER REGULATORY LIABILITIES	**$000s**	**$000s**	**$000s**
Income Taxes - Federal	$ 4,262		4,262
Income Taxes - State	3,097		3,097
Other Regulatory Liabilities-Pension OK 2009	8,149		8,149
	$ 15,508	-	$ 15,508

Note 1 - Return Recovered through Rider
Note 2 - Non-jurisdictional
Note 3 - Fully Amortized as of July 2011
Note 4 - Reclassified to Net Pension Benefits Asset