Control Number: 40443

Item Number: 630

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SOAH DOCKET NO. 473-12-7519
PUC DOCKET NO. 40443

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES AND RECONCILE FUEL COSTS	§ § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY

OF

LANE KOLLEN

ON BEHALF OF THE

CITIES SERVED BY SWEPCO

DECEMBER 10, 2012

630

DIRECT TESTIMONY OF
LANE KOLLEN

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WORKPAPERS

I. QUALIFICATIONS AND SUMMARY

A. Qualifications

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Lane Kollen. I am a Vice President and Principal of J. Kennedy and Associates, Inc., an economic consulting firm specializing in utility ratemaking and planning issues. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I provide this information in Attachment 1.

Q. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY IN THIS PROCEEDING?

A. I am providing testimony on behalf of the Cities Served by SWEPCO ("Cities"), an ad hoc group of municipalities who, along with the residents and businesses within the municipalities, receive electric service from Southwestern Electric Power Company ("SWEPCO" or "Company").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS?

A. Yes. I have testified before the Public Utility Commission of Texas ("PUC" or "Commission") on numerous occasions. In my testimonies, I addressed various subjects, including revenue requirements, stranded costs, securitization, advanced metering systems, and rate case expenses, among others. Most recently, I testified on behalf of the

Steering Committee of Cities Served by Oncor in the Cross Texas Transmission, LLC rate proceeding, Docket No. 40604.[1]

In addition, I testified on revenue requirement issues in Docket No. 40020, a Lone Star Transmission, LLC base rate proceeding; Docket No. 35717,[2] an Oncor Electric Delivery Company, LLC ("Oncor") base rate proceeding; Docket No. 38339,[3] a CenterPoint Electric Delivery Company, LLC ("CenterPoint") base rate proceeding; and Docket Nos. 33309[4] and 33310,[5] AEP Texas Central Company and AEP Texas North Company base rate proceedings. I provide a list of my testimonies and expert appearances by docket number and a brief description of the subject matter of each testimony in Attachment 1.

B. Summary

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address and make recommendations on specific revenue requirement issues, quantify the effects on the Company's revenue requirement of Cities' witness Mr. Steve Hill's recommendations, and summarize the effect on the revenue requirement of all Cities' recommendations.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission authorize a base rate increase of no more than $15.862 million. This recommendation reflects numerous adjustments to the Company's filed

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1 *Application of Cross Texas Transmission, LLC to Establish Initial Rates and Tariffs*, Docket No. 40604.

2 *Application of Oncor Electric Delivery Company, LLC for Authority to Change Rates*, Docket 35717.

3 *Application of CenterPoint Electric Delivery Company, LLC for Authority to Change Rates*, Docket No. 38339.

4 *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309.

5 *Application of AEP Texas North Company for Authority to Change Rates*, Docket No. 33310.

request to increase rates by $83.607 million, which are listed and quantified in the following table, referred to as the "Summary Table." I address many of the rate base and cost of service adjustments to the Company's filed request. Other rate base and cost of service adjustments are addressed by Ms. Connie Cannady. Mr. Clarence Johnson addresses the weather normalization revenue adjustment and the effects of the variable environmental expenses in base rates. Mr. Steve Hill addresses the return on equity. I identify Cities' witnesses responsible for each of the adjustments in the final column of the Summary Table. Although I identify Mr. Hill as the witness responsible for the return on equity recommendations, I quantify the effect on the revenue deficiency of Mr. Hill's recommendations in the final section of my testimony. In addition, certain of Cities' adjustments are addressed by Cities Advocating Reasonable Deregulation ("CARD") witness Mr. Mark Garrett.

PUC Docket No. 40443
Southwestern Electric Power Company
Texas Retail Revenue Requirement
Summary of Cities Recommendations
($ Millions)

Issue	Return	Expense	Rev	Total	Cities Witness
Rate Base Adjustments					
Remove Turk Transmission CWIP at 12/31/2011 Net of ADFIT	(1.137)	(0.448)		(1.585)	Kollen
Remove Turk Transmission CWIP Projected During 2012 Net of ADFIT	(0.550)	(0.217)		(0.767)	Kollen
Remove Turk Plant Costs Above Cap on Prorata Basis Plus Related AFUDC	(3.642)	(1.437)		(5 079)	Kollen
Remove Costs of Turk Auxiliary Boiler Net of ADFIT	(0.342)	(0.135)		(0.477)	Kollen
Reduce Turk Plant Land Costs	(0.137)	(0.054)		(0.191)	Cannady
Remove Settlements, Legal Costs and Other from Turk Plant Costs	(0.677)	(0.267)		(0.944)	Cannady
Remove Attorneys Fees from Turk Plant Costs	(0.232)	(0.091)		(0.323)	Cannady
Remove Incentive Compensation Tied to Financial Performance from Turk Plant Costs	(0.014)	(0.006)		(0.020)	Cannady
Reduce Incentive Compensation Tied to Financial Performance for Non-Turk Plant Cos	(0.045)	(0.018)		(0.062)	Cannady
Remove Prepaid Pension Asset Net of ADFIT	(1.511)	(0.596)		(2.107)	Cannady
Remove Regulatory Asset for Mountaineer Carbon Capture Study	(0.043)	(0.017)		(0.060)	Kollen
Rate of Return Adjustments					
Reduce Return on Equity to 9.0%	(12.145)	(7.188)		(19.333)	Hill
Reduce Return on Equity for DHLC to 9.0%		(0.037)		(0.037)	Kollen
Revenue and Cost of Service Adjustments					
Remove Weather Normalization of Revenues			(7.381)	(7.381)	Johnson
Include Variable Environmental Costs in Base Rates		0.886		0.886	Johnson
Reduce SWEPCO and AEPSC Short Term Incentive Plan Compensation		(1.229)		(1.229)	CARD/Garrett
Remove SWEPCO and AEPSC Long Term Incentive Plan Compensation		(1.783)		(1.783)	CARD/Garrett
Remove SWEPCO and AEPSC SERP		(0.196)		(0.196)	CARD/Garrett
Reduce Payroll Base Pay for SWEPCO and AEPSC Employees		(1.336)		(1.336)	Cannady
Remove Amortization of 2010 Severance Costs		(2.136)		(2.136)	CARD/Garrett
Reduce Qualified Pension, FAS 106, And FAS 112 Benefits - SWEPCO and AEPSC		(1.302)		(1.302)	Cannady
Remove Post Test Year Increase in Vegetation Management Expense		(2.586)		(2.586)	Kollen
Reduce Post Test Year Estimated O&M Expense for Turk Plant		(1.489)		(1.489)	Kollen
Normalize Obsolete Inventory Expense Chargeoffs		(0.108)		(0.108)	Kollen
Normalize Injuries and Damages Expense		(0.691)		(0.691)	CARD/Garrett
Exclude Normalized Nonrecurring Settlement Costs from Injuries and Damages Expense		(0.038)		(0.038)	Kollen
Remove Credit Line Fees Reclassification		(0.419)		(0.419)	Cannady
Remove Mountaineer Carbon Capture Storage Study Amortization Expense		(0.161)		(0.161)	Kollen
Reduce Amortization of Hurricane Ike and Gustav Costs		(0.276)		(0.276)	Kollen
Remove Depr and AVT Expense for Turk Trans. CWIP at 12/31/2011		(0.612)		(0.612)	Kollen
Remove Depr and AVT Expense for Turk Trans. CWIP Projected During 2012		(0.310)		(0.310)	Kollen
Remove Depr and AVT Expense for Turk Plant Costs Above Cap		(1.554)		(1.554)	Kollen
Remove Depr and AVT Expense for Turk Plant Auxiliary Boiler		(0.152)		(0.152)	Kollen
Remove Depr and AVT Expense for Turk Settlement, Legal, and Other Costs		(0.302)		(0.302)	Cannady
Remove Depr and AVT Expense for Turk Attorneys Fees		(0.103)		(0.103)	Cannady
Remove Depr and AVT Expense for Turk Incentive Compensation		(0.006)		(0.006)	Cannady
Remove Depr and AVT Expense for Non-Turk Incentive Compensation		(0.026)		(0.026)	Cannady
Reduce Depreciation Expense for Welsh 2 to Utilize 60 Year Life Span		(1.079)		(1.079)	Kollen
Reduce Depreciation Expense for Dolet Hills to Utilize 60 Year Life Span		(1.152)		(1.152)	Kollen
Reduce Depreciation Expense for Stall to Utilizie 45 Year Life Span		(0.977)		(0.977)	Kollen
Reduce Depreciation Expense for Turk to Utilize 60-Year Life Span		(3.594)		(3.594)	Kollen
Reduce Depreciation Expense to Remove Estimated Dismantlement Costs		(1.103)		(1.103)	Kollen
Reduce Payroll Taxes Expense Related to Cities Payroll Related Recommendations		(0.562)		(0.562)	Cannady
Adjust Income Tax Expense for Consolidated Tax Savings Adjustment		(4.982)		(4.982)	Kollen
Total Cities Adjustments	(20.476)	(39.889)	(7.381)	(67.745)	
SWEPCO Total Claimed Base Rate Rev. Requirement	102.728	258.015	-	360.743	
Cities Total Base Rate Revenue Requirement	82.252	218.127	(7.381)	292.998	
SWEPCO Test Year Total Base Rate Revenues				277.136	
Cities Total Base Rate Revenue Surplus/(Deficiency)				(15.862)	
SWEPCO Claimed Total Base Rate Surplus/(Deficiency) Per Filing				(83.607)	

The amounts shown on the preceding table are Texas retail jurisdictional amounts. Similarly, the amounts that I cite in my testimony are Texas retail jurisdictional amounts unless otherwise indicated as total Company amounts. The revenue requirement amounts shown on the preceding table for the revenue and expense adjustments generally are slightly more than the underlying adjustments cited by Cities' witnesses in their testimony due to the gross-ups for various fees and taxes (other than income taxes). These gross-ups are shown in my schedules and workpapers. The revenue requirement amounts shown on the preceding table for the adjustments addressed by CARD witness Mr. Garrett also reflect the gross-ups for various fees and taxes and are slightly more than the amounts he cites in his testimony for that reason.

Finally, in the last section of my testimony, I address the cost of my firm's services to Cities as a reasonable rate case expense. I describe the scope and cost of the services provided, our billing practices, and our hourly billing rates.

II. RATE BASE ISSUES

A. Reject Turk Transmission CWIP

Q. PLEASE DESCRIBE THE COMPANY'S REQUEST TO INCLUDE TURK TRANSMISSION CONSTRUCTION WORK IN PROGRESS IN RATE BASE.

A. The Company proposes two post test year adjustments to include \$72.661 million (total Company) of Turk transmission construction work in progress ("CWIP") in rate base as shown on Schedule B-1.4. The request includes the actual amount of \$48.253 million (total Company) in CWIP at December 31, 2011 plus another estimated \$24.408 million (total Company) that the Company estimates it will spend to complete the transmission facilities.

Q. WHAT IS THE BASIS FOR THE COMPANY'S REQUEST TO INCLUDE THIS TRANSMISSION CWIP IN RATE BASE?

A. The Company's request ostensibly is based on P.U.C. SUBST. R. 25.231(c)(2)(F), according to Mr. Randall Hamlett.[6] P.U.C. SUBST. R. 25.231(c)(2)(F) sets forth four specific requirements for post-test year adjustments to invested capital, or rate base, as follows:

> **<u>§25.231(c) continued</u>**
>
> (2) **Invested capital; rate base.** The rate of return is applied to the rate base. The rate base, sometimes referred to as invested capital, includes as a major component the original cost of plant, property, and equipment, less accumulated depreciation, used and useful in rendering service to the public. Components to be included in determining the overall rate base are as set out in subparagraphs (A)-(F) of this paragraph.
>
> ***
>
> (F) Requirements for post test year adjustments.
>
> (i) Post test year adjustments for known and measurable rate base additions (increases) to historical test year data will be considered only as set out in subclauses (I)-(IV) of this clause.
>
> (I) Where the addition represents plant which would appropriately be recorded:
>
> (-a-) for investor-owned electric utilities in FERC account 101 or 102;
>
> (-b-) for electric cooperatives, the equivalent of FERC accounts 101 or 102.
>
> (II) Where each addition comprises at least 10% of the electric utility's requested rate base, exclusive of post test year adjustments and CWIP.
>
> (III) Where the plant addition is deemed by this commission to be in-service before the rate year begins.
>
> (IV) Where the attendant impacts on all aspects of a utility's operations (including but not limited to, revenue, expenses and invested capital) can with reasonable certainty be identified, quantified and matched. Attendant impacts are those that reasonably follow as a consequence of the post test year adjustment being proposed.

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6 Direct Testimony of Randall W. Hamlett at 37-38 (July 27, 2012).

> (ii) Each post test year plant adjustment will be included in rate base at:
>
> (I) the reasonable test year-end CWIP balance, if the addition is constructed by the electric utility; ...

These requirements apply to "each post test year plant adjustment" or "each addition," not to multiple aggregated adjustments. Although not specifically addressed by Mr. Hamlett in his Direct Testimony, the Company applied the 10% test required by P.U.C. SUBST. R. 25.231(c)(2)(F)(i)(II) only to the Turk plant CWIP, and not to the Turk transmission CWIP, or the Turk plant and Turk transmission CWIP in the aggregate. The Company's exclusion of the Turk transmission CWIP when it applied the 10% test, suggests that the Company itself considers the Turk transmission CWIP as a separate addition in and of itself. It also is significant that the Company does not claim that the Turk transmission CWIP meets the 10% test on its own as a separate addition.

Although it does not qualify the Turk transmission CWIP on its own or in the aggregate with the Turk plant CWIP, the Company attempts to piggyback the Turk transmission CWIP on the Turk plant CWIP by characterizing the Turk transmission CWIP as an "attendant impact" of the Turk plant CWIP, apparently relying on P.U.C. SUBST. R. 25.231(c)(2)(F)(i)(IV).[7] The Turk transmission CWIP on its own does not meet the requirement in P.U.C. SUBST. R. 25.231(c)(2)(F)(i)(II), which requires that *each addition* comprise at least 10% of the utility's rate base, exclusive of post test year adjustments and CWIP.[8] In fact, the Company shows the Turk plant CWIP and its "attendant impacts" and the Turk transmission CWIP and its "attendant impacts" as

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[7] *Id.* at 41-42.

[8] The total Company Turk transmission CWIP ($72.661 million total Company) is only 3.1% of the Company's rate base ($2,311 million total Company as shown in Direct Testimony of Randall W. Hamlett at 38, *see* table).

separate components of the Company's "Turk" post test year adjustments on Schedule B-1.4 page 1 of 2.

It should be noted that the Company does not claim to base its request on P.U.C. SUBST. R. 25.231(c)(2)(D), which sets forth the requirements to include CWIP in rate base.

Q. SHOULD THE TURK TRANSMISSION CWIP STAND ON ITS OWN AS A PROPOSED TEST YEAR ADDITION ALONG WITH ITS SEPARATE "ATTENDANT IMPACTS"?

A. Yes. P.U.C. SUBST. R. 25.231(c)(2)(F) applies to "each post test year plant adjustment" or "each addition" and each such adjustment must meet all four of the requirements that are set forth in the rule. The Turk plant CWIP and the Turk transmission CWIP are separate CWIP projects, separate additions, and will be accounted for separately as production plant and transmission plant, respectively. In fact, the so-called Turk transmission CWIP actually consists of multiple transmission lines and stations, nine of which are shown as separate CWIP projects on Schedule C-4.1. Some of the so-called Turk transmission projects were already in service at December 31, 2011, and not included in the Turk transmission CWIP or the Turk post test year adjustment, according to Mr. Hamlett.[9] In other words, the Turk transmission projects already in service at December 31, 2011, were included in rate base as transmission plant in-service independent of the Turk plant. In contrast to the Turk transmission projects that already were in service at the end of the test year, the Company included none of the Turk plant as in-service at the end of the test year.

---

[9] Direct Testimony of Randall W. Hamlett at 41 (July 27, 2012).

The Turk plant CWIP and the Turk transmission CWIP each should be considered separate additions. They are separate and distinct CWIP projects, and each will be separate and distinct assets when placed in-service that will perform different functions. The Turk plant is a generating unit that will produce power. The Turk transmission lines, substations and other facilities transmit power and are interconnected not only with the Turk plant, but also with other transmission facilities. The Turk plant and the Turk transmission facilities are physically separate, except for the portion of the transmission facilities that actually are located on the Turk plant site. The operations of the distinct assets are separate, and they are even conducted by different companies. SWEPCO will operate the power plant. The AEP Transmission Division operates and maintains all of the transmission lines and facilities, according to Company witness Mr. Matthews.[10]

The transmission lines and other facilities were placed in-service as each component was completed and each line segment was energized independent of and before the Turk plant itself is scheduled to be placed in-service.[11] In fact, the transmission lines and other facilities were completed and in-service by the end of August 2012, according to an AEP article describing the status of the project.[12] The transmission assets include 15 transmission lines extending over 110 miles, including two 138 kV lines and one 345 kV line, 12 station facilities, and six river crossings, also according to the AEP article.

When viewed from the perspective that the Turk plant CWIP and the Turk transmission CWIP each should be separate adjustments, then the Turk transmission

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10 Direct Testimony of Charles D. Matthews at 8 (July 27, 2012).

11 *Id.* at 33-34.

12 *See* Attachment 2.

CWIP is not an "attendant impact" of the Turk plant CWIP. The rule itself defines "attendant impacts" as "those that reasonably follow as a consequence of the post test year adjustment being proposed."[13] The Company's other proposed Turk plant CWIP attendant impacts for ADIT, coal inventory, depreciation expense, ad valorem tax expense, O&M expense, and federal income tax expense may be "those that reasonably follow as a consequence." However, the Turk transmission CWIP, as a separate and distinct "addition," in and of itself, does not "reasonably follow as a consequence" of the proposed Turk plant CWIP. In fact, the completion of the Turk transmission assets preceded the completion of the Turk plant; it did not "follow as a consequence." The Turk transmission CWIP should stand on its own and be assessed on its own as a separate addition, and with its own "attendant impacts" that "reasonably follow as a consequence," which include ADIT as shown on Schedule B-1.4 page 1 of 2.

Q. ALTHOUGH THE COMPANY DOES NOT BASE ITS REQUEST TO INCLUDE THE TURK TRANSMISSION CWIP ON P.U.C. SUBST. R. 25.231(C)(2)(D), WOULD IT NONETHELESS QUALIFY UNDER THAT SECTION OF THE SUBSTANTIVE RULE?

A. No. The inclusion of the Turk transmission CWIP is not necessary to the financial integrity of the utility, a specific requirement set forth in P.U.C. SUBST. R. 25.231(c)(2)(D)(i)(I).

Q. IF THE COMMISSION IS INCLINED TO ALLOW THE COMPANY'S PROPOSED TURK TRANSMISSION CWIP IN RATE BASE, IS THERE ANOTHER ISSUE THAT SHOULD BE CONSIDERED?

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13 P.U.C. SUBST. R. 25.231(c)(2)(F)(i)(IV).

A. Yes. P.U.C. SUBST. R. 25.231(c)(2)(F)(ii)(I) limits the amount of any post test year adjustment for CWIP to "the reasonable test year-end CWIP balance, if the addition is constructed by the electric utility." As I previously described, the Company's request for the Turk transmission CWIP in rate base consists of two amounts: $48.253 million (Total Company) for the CWIP at December 31, 2011, and an additional $24.408 million (Total Company) for amounts the Company estimates that it will spend after the end of the test year to complete the projects. The additional $24.408 million (Total Company) that the Company estimates it will spend after the end of the test year does not qualify even if the Turk transmission CWIP is considered an "attendant impact" of the Turk plant CWIP.

In addition, the Company's request for the additional $24.408 million (Total Company) in Turk transmission CWIP as an "attendant impact" is inconsistent with the Company's request for the Turk plant CWIP, which it limited to the test year-end CWIP balance, as described by Mr. Hamlett and as shown on Schedule B-1.4.

Thus, if the Commission is inclined to consider the Turk transmission CWIP as an "attendant impact" of the Turk plant CWIP, then it should apply the limitations set forth in the rule not only to the Turk plant CWIP, but also to the Turk transmission CWIP.

Q. WHAT IS YOUR RECOMMENDATION?

A. The Commission should exclude the Turk transmission CWIP from rate base. The Turk transmission CWIP does not qualify under P.U.C. SUBST. R. 25.231(c)(2)(D)(i)(I) as CWIP necessary to the Company's financial integrity. It does not qualify under P.U.C. SUBST. R. 25.231(c)(2)(F)(i)(II) as a separate addition that comprises at least 10% of the electric utility's rate base. And it does not qualify under P.U.C. SUBST. R. 25.231(c)(2)(F)(i)(IV) as an "attendant impact" of the Turk plant CWIP.

Alternatively, and at a minimum, the Commission should exclude the $24.408 million (Total Company) in Turk transmission CWIP that the Company estimates it will spend after the end of the test year because it does not qualify under P.U.C. SUBST. R. 25.231(c)(2)(F)(ii)(I), which limits the post test year adjustment for CWIP to the test year-end balance.

Q. HAVE YOU QUANTIFIED THE EFFECT OF YOUR RECOMMENDATION ON THE COMPANY'S REVENUE REQUIREMENT?

A. Yes. The effect is a reduction of $3.274 million to the Company's revenue requirement, consisting of $2.197 million for the CWIP at December 31, 2011 and $1.077 million for the additional estimated spending after the end of the test year. I show these two amounts separately in the Summary Table. On a separate basis, the second of these two amounts reflects the quantification of the revenue requirement effect for my alternative recommendation.

I provide the computations on Schedule LK-1. I used the Company's proposed grossed-up rate of return to quantify the effect. I replicated the Company's proposed rate of return in Section I on Schedule LK-14 and then computed the grossed-up rate of return using the gross-up factor shown on Mr. Hamlett's Exhibit RWH-3. That gross-up factor includes federal income tax rate and other fees and tax rates as shown on Mr. Hamlett's exhibit and described in his testimony.[14] In addition, I reflected the effects on all of the other capital-related expenses (depreciation expense, ad valorem tax expense) in the Summary Table and on Schedule LK-1.

[14] Direct Testimony of Randall W. Hamlett at 15-16 (July 27, 2012).

B. Reduce Turk Plant Costs to Reflect the Cost Cap Set by PUC in Docket No. 33891

Q. PLEASE DESCRIBE THE COMPANY'S IMPAIRMENT LOSS WRITE-OFF ON TURK CWIP THAT IT TOOK IN DECEMBER 2011 ON ITS ACCOUNTING BOOKS, AND ITS PROPOSED ADJUSTMENT TO REVERSE THIS WRITE-OFF FOR RATEMAKING PURPOSES.

A. The Company took an impairment loss write-off of $49 million (Texas retail) on Turk CWIP on its accounting books in December 2011 to reflect the effects of the cost cap set by the Commission in the Turk CCN proceeding, Docket No. 33891. The projected costs for the Turk plant already exceeded the cost cap as of December 31, 2011, according to the Notes to the Financial Statements included in the Company's 2011 10-K and in its FERC Form No. 1.[15] In the 2011 10-K, the Company states:

> The PUCT issued an order approving a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO_2 emission costs at $28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant should be revoked because the Turk Plant is unnecessary to serve retail customers. In February 2010, the Texas District Court affirmed the PUCT's order in all respects. In March 2010, SWEPCo and the Texas Industrial Energy Consumers appealed this decision to the Texas Court of Appeals. In November 2011, the Texas Court of Appeals affirmed the PUCT's order in all respects. As a result, in the fourth quarter of 2011, SWEPCo recorded a pretax write-off of $49 million in Asset Impairment and Other Related Charges on the statement of income related to the estimated excess of

[15] Attachments 3 and 4.

the Texas jurisdictional portion of the Turk Plant above the Texas jurisdictional capital costs cap.[16]

The Company proposes to restore the impairment loss write-off by adding the $49 million back to the Turk plant CWIP. This adjustment is shown on Schedule B-1.5 as Adjustment B-1.5.14 and is described by Mr. Hamlett.[17] Mr. Hamlett argues that "SWEPCO's request in this case is based upon an actual amount of costs incurred through December 2011 and not an estimated amount once the plant is completed."[18]

Q. HOW DID THE COMPANY CALCULATE THE IMPAIRMENT LOSS WRITE-OFF?

A. The impairment loss write-off was based on the Company's most recent estimate at December 31, 2011, of the total cost of the Turk plant, excluding AFUDC, compared to the Commission's total cost cap, excluding AFUDC. The Company then applied its ownership share and multiplied it times an estimated Texas retail jurisdictional percentage. The Company's response to TIEC's RFI No. 10-3 describes the calculation of the impairment loss write-off and provides a Confidential attachment with the updated calculation as of the beginning of the third quarter of 2012.[19] The impairment loss write-off included only the Turk plant direct costs and did not include any of the related AFUDC.

Q. SHOULD THE $49 MILLION IMPAIRMENT LOSS WRITE-OFF BE RESTORED TO THE TURK PLANT CWIP AND INCLUDED IN RATE BASE?

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[16] Attachment 3 at 242.

[17] Direct Testimony of Randall W. Hamlett at 40 and 50 (July 27, 2012).

[18] *Id.* at 40.

[19] Attachment 5 (SWEPCO's Response to TIEC's RFI No. 10-3); Attachment 6 (SWEPCO's Response to TIEC's RFI No. 10-3, Confidential Attachment 1).

A. No. The Commission should restore only a portion of the impairment write-off. The $49 million impairment loss write-off represents the entirety of the amount that the Company estimates it will incur for the Turk plant in excess of the Commission's total cost cap and that will not be allowed recovery by the Commission. In other words, the impairment loss write-off for accounting purposes assumes that the excess was caused entirely by the costs already incurred as of December 31, 2011. However, the Commission must determine if the write-off for accounting purposes should be recognized for ratemaking purposes, and if so, how much of the write-off should be recognized for ratemaking purposes consistent with the cost cap set in the certification proceeding.

Q. PLEASE RESPOND TO THE COMPANY'S ARGUMENT THAT THE TURK PLANT CWIP AT DECEMBER 31, 2012, DID NOT EXCEED THE TOTAL COST CAP AND THEREFORE THE IMPAIRMENT LOSS WRITE-OFF SHOULD BE RESTORED.

A. The Company's argument is flawed. All of the Turk plant construction costs contribute to the excess over the total cost cap. The impairment loss write-off calculation for accounting purposes assumes that only the first dollars contribute to the excess. In contrast, the Company argues that for ratemaking purposes only the last dollars contribute to the excess.

However, neither of these positions is correct for ratemaking purposes because all of the construction costs contribute to the excess, not only the first dollars and not only the last dollars. This is because the total estimated cost and the total cost cap necessarily are the sum of all costs, not only the first or last dollars.

Consider the following example. Assume that the total estimated cost for the Turk plant is $1,750 million, the total cost cap is $1,600 million, and the CWIP is $1,500 million at December 31, 2011. Under the accounting rules, the Company would be required to record an impairment loss of $150 million ($1,750 million less $1,600 million) at December 31, 2011, essentially reducing the CWIP to $1,350 million ($1,500 million less $150 million) at December 31, 2011. This is the "first dollars" approach. Under the Company's view, the CWIP should remain at $1,500 million at December 31, 2011, for ratemaking purposes. This is the "last dollars" approach. Neither of these approaches is correct for ratemaking purposes because each approach attributes the cause of the excess exclusively to first or last dollars when, in fact, all dollars contribute to the excess.

The correct approach for ratemaking purposes is to prorate the disallowance across all construction costs because all construction costs contribute equally to the excess. This is the "pro rata" approach. Under this approach, the excess over the cost cap, or total disallowance, is allocated to the Turk plant CWIP at December 31, 2011, on the ratio of the CWIP at that date to the total estimated cost. Under the preceding example, the $150 million disallowance would be allocated $129 million to the CWIP at December 31, 2011 ($150 million / $1,750 million x $1,500 million) and $21 million to the remaining total estimated cost.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission use the "pro rata" approach. Such an approach allocates the disallowance proportionately to each dollar of cost incurred.

Q. IS THERE ANOTHER ISSUE THAT SHOULD BE ADDRESSED IN CONJUNCTION WITH THE DISALLOWANCE?

A. Yes. The Company's calculation of the disallowance is based only on direct costs; it did not include the related effects of the AFUDC that has been accrued as a direct result of the excess direct costs. The AFUDC represents the accumulated financing costs that have been capitalized on direct and AFUDC costs (due to compounding). If the direct costs for ratemaking purposes are less than actually incurred due to the cost cap, then the AFUDC also should be less because it is dependent on the direct costs.

The fact that the Company has not written off any AFUDC for accounting purposes suggests that either it does not agree that any of the related AFUDC should be disallowed due to the cost cap or that it has adopted a "wait and see" approach to see if the Commission identifies this issue and, if so, how it decides it.

The Commission should ensure that there is no ambiguity on this point. If the actual direct costs are disallowed due to the cost cap, then the related AFUDC also should be disallowed because the excess direct costs necessarily resulted in additional and excess AFUDC. Thus, the Commission also should disallow a pro rata amount of the AFUDC in addition to the direct costs.

Q. HAVE YOU QUANTIFIED THE EFFECT OF YOUR RECOMMENDATION?

A. Yes. The effect is a reduction in the revenue requirement of $6.4633 million. I provide the calculations on Schedule LK-2. On this schedule, I prorate the $49 million disallowance between the Turk plant CWIP at December 31, 2011, and the total estimated cost as reported in the Company's 2011 10-K. In addition, I have prorated the estimated AFUDC related to the disallowance of direct costs. The result is a disallowance of the Turk plant CWIP of $50.007 million. Before the offset for ADIT, I then multiply the disallowance net of ADIT times the Company's grossed-up rate of return. In addition, I reflected the effects on all of the other capital-related expenses in the Summary Table and on Schedule LK-2.

C. <u>Reduce Turk Plant Costs to Remove Cost of Auxiliary Boiler That Is Not Used and Useful</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO INCLUDE THE COSTS OF AN UNUSED AUXILIARY BOILER IN RATE BASE AND THE CAPITAL-RELATED OPERATING EXPENSES IN COST OF SERVICE.

A. The Company's proposal is described by Ms. McCellon-Allen.[20] The Company proposes to include more than $15.0 million (total Company) for an auxiliary boiler in the post test year adjustment for the Turk plant CWIP. The Company purchased the boiler, but did not use it in the actual construction of the Turk plant because it would have required a modification of the final Turk air permit. Instead, the Company subsequently purchased and used another boiler in the actual construction of the Turk plant that complied with the original specifications approved in the final air permit. The Company now is attempting to sell the auxiliary boiler and proposes to apply any funds from a sale to a third party as a reduction to the cost of the Turk plant.

The $15.0 million cited by Ms. McCellon-Allen is only the direct cost of the boiler purchased by the Engineering, Procurement, and Construction contractor and does not include other costs such as overheads or AFUDC, according to the Company's response to TIEC's RFI No. 5-19(c). In other words, the actual cost is more than $15.0 million, but the Company refused to provide a quantification of the additional costs in response to TIEC's RFI No. 5-19(c).[21]

Q. SHOULD THE COMMISSION INCLUDE THE COST OF THIS AUXILIARY BOILER IN RATE BASE?

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[20] Direct Testimony of Venita McCellon-Allen at 45-46 (July 27, 2012).

[21] Attachment 7 (SWEPCO's Response to TIEC's RFI No. 5-19).

A. No. The auxiliary boiler is not used and useful in rendering service to the public, a prerequisite for inclusion in rate base, except for certain CWIP exceptions, as set forth in P.U.C. SUBST. R. 25.231(c)(2), which states: "The rate base, sometimes referred to as invested capital, includes as a major component the original cost of plant, property, and equipment, less accumulated depreciation, *used and useful* in rendering service to the public." (emphasis added).

Q. DOES THE COMPANY'S PROPOSAL TO CREDIT THE COST OF THE TURK PLANT WITH ANY SALES PROCEEDS FROM THE BOILER CURE THE FUNDAMENTAL FACT THAT THE ASSET IS NOT USED AND USEFUL?

A. No. The boiler is not used and useful. The Company's proposal does not cure this fundamental fact or overcome this threshold requirement to include the cost in rate base.

Q. SHOULD THE COST OF THE AUXILIARY BOILER BE INCLUDED IN RATE BASE?

A. No. First, the asset is not used and useful. Second, the costs were not prudently incurred. Ms. McCellon-Allen acknowledges that the Company incurred the cost of this boiler before fully considering the impact on its final air permit or discussing with the Arkansas Department of Environmental Quality the modification of the specifications or substitution of the original boiler with a smaller boiler. This decision was not prudent based on the circumstances that Ms. McCellon-Allen describes. Thus, the cost of this decision should be borne by SWEPCO, not its customers. Any proceeds from the sale of the auxiliary boiler should be retained by SWEPCO to offset the cost that it incurred.

Q. HAVE YOU QUANTIFIED THE EFFECT OF YOUR RECOMMENDATION ON THE COMPANY'S REVENUE REQUIREMENT?

A. Yes. The effect is a reduction of $0.629 million to the Company's revenue requirement. I provide the computations on Schedule LK-3. I used the Company's proposed grossed-up rate of return to quantify the effect. In addition, I reflected effects on all of the other capital-related expenses in the Summary Table and on Schedule LK-3. I note that this quantification does not include any effects for the related overheads and AFUDC.

D. <u>Reject Mountaineer Carbon Capture Study Regulatory Asset</u>

Q. PLEASE DESCRIBE THE COMPANY'S REQUEST TO INCLUDE MOUNTAINEER CARBON CAPTURE STUDY COSTS AS A REGULATORY ASSET IN RATE BASE AND TO AMORTIZE THE COSTS OVER THREE YEARS.

A. The Company requests a regulatory asset of $0.777 million (Texas Retail) in rate base for costs allocated to SWEPCO by AEP from Appalachian Power Company related to the Commercial Scale Carbon Capture and Sequestration ("CCS") Project at the Mountaineer Plant owned by Appalachian Power Company.[22] In addition to the costs in rate base, the Company also seeks $0.155 million (Texas retail) in amortization expense to recover the costs over five years.[23]

Q. DID SWEPCO SEEK OR OBTAIN AUTHORIZATION FROM THE COMMISSION TO DEFER THESE COSTS AS A REGULATORY ASSET?

A. No. SWEPCO had no authority to defer these costs in account 182 as a regulatory asset. Absent such authority, the costs should have been expensed when incurred. In addition, SWEPCO had no decision-making input or oversight on this project or its costs.

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[22] Direct Testimony of Paul W. Franklin at 58-59 (July 27, 2012); *see also* Attachment 8 (SWEPCO's Response to Staff's RFI No. 6-1).

[23] Direct Testimony of Randall W. Hamlett at 30 (July 27, 2012).

Further, the allocation of the project's costs to SWEPCO occurred only after the Virginia Corporation Commission ("VCC") denied Appalachian Power Company's request for recovery of 50% of the costs and the West Virginia Public Service Commission reduced Appalachian Power Company's request for recovery of the other 50% of the costs on the basis that the costs should be allocated among all the AEP operating companies.[24] In response to CARD'S RFI No. 18-21, the Company provided copies of testimony before the regulatory agencies in other jurisdictions in which it sought recovery of the Mountaineer CCS costs and the orders or links to the orders in the relevant proceedings. In its Order in Case No. PUE-2009-00030, the Virginia Corporation Commission stated:

> It is reasonable for AEP to evaluate and explore options regarding potential federal legislation or regulation regarding GHG emissions. We do not find, however, that it was reasonable for APCo to incur the Mountaineer CCS project costs and then seek recovery from Virginia ratepayers. For example: (i) although AEP asserts that this demonstration project will benefit customers of all of AEP's operating companies and of all utilities in the United States, APCo's ratepayers (and not shareholders) are being asked to pay for all of the costs incurred by AEP for this project; and (ii) as stated by Consumer Counsel, 'AEP is undertaking no other [CCS] initiatives at any of its other subsidiaries' plants,' and 'APCo and its customers are being asked to shoulder the entire financial burden and risk associated with AEP's [CCS] research and development.' Accordingly, we deny the Company's request for cost recovery of the Mountaineer CCS demonstration project under the facts presented herein.[25]

Q. SHOULD THE COMMISSION AUTHORIZE RECOVERY OF THESE COSTS?

A. No. First, in the absence of an order from the Commission, the Company should not have deferred the costs. The Commission should not allow a retroactive deferral. A

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[24] Attachment 9 (SWEPCO's Response to CARD's RFI No. 18-21).

[25] *Id.* at *Application of Appalachian Power Company*, Virginia State Corporation Commission, Case No. PUE-2009-00030, Final Order at 20-21 (July 15, 2010).

retroactive deferral is functionally equivalent to a deferred rate increase and would constitute impermissible retroactive ratemaking. Second, the costs were incurred by Appalachian Power Company; neither the Commission nor the Company had any decision-making involvement in, or oversight over, the incurrence of the costs. AEP allocated the costs to SWEPCO only after the Virginia Corporation Commission denied Appalachian Power Company recovery and the West Virginia Commission reduced the requested recovery. Third, the Company has identified no tangible benefits from the project.

Q. HAVE YOU QUANTIFIED THE EFFECT OF YOUR RECOMMENDATION ON THE COMPANY'S REVENUE REQUIREMENT?

A. Yes. The effect is a reduction of $0.221 million to the Company's revenue requirement. I provide my computations on Schedule LK-4. I used the Company's proposed grossed-up rate of return to quantify the effect of removing the regulatory asset, net of the related ADIT, from rate base. I also provide the quantifications of the related expenses, including the amortization expense and the Texas margin tax expense on Schedule LK-4 and show these amounts separately in the Summary Table.

III. COST OF SERVICE ISSUES

A. Reject Proposed Increases in Vegetation Management Expense

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED INCREASE IN VEGETATION MANAGEMENT EXPENSE.

A. The Company seeks increased revenues to fund an additional $2.1 million (Texas retail) in distribution vegetation management and an additional $0.4 million (Texas retail) in transmission vegetation management, according to Ms. McCellon-Allen.[26] The Company's request for an increase in revenues to fund additional vegetation management expenses is reiterated by Mr. Smoak (distribution) and Mr. Matthews (transmission), although neither witness provides additional information regarding how the additional funds would be used other than to perform additional trimming activities. Neither witness addresses any savings that could or would be achieved due to reduced outage and maintenance expense. Further, neither witness provides a cost/benefit analysis showing that the maintenance savings from the additional trimming will exceed the cost to customers.[27] Finally, the SAIFI and SAIDI statistics provided by Mr. Smoak for the years 2005-2011 show a significant deterioration in outage frequency and duration in 2011 even after the one-time surcharge to fund increased vegetation management over two years as a result of the settlement in Docket No. 37364.[28]

Q. HOW DOES THE COMPANY'S ACTUAL VEGETATION MANAGEMENT EXPENSE INCURRED IN THE TEST YEAR, EXCLUDING THE ADDITIONAL EXPENSE RELATED TO THE SURCHARGE PURSUANT TO THE SETTLEMENT IN DOCKET NO. 37364, COMPARE TO THE ACTUAL EXPENSE INCURRED IN PRIOR YEARS?

A. The actual vegetation management expense incurred in the test year and reflected in the revenue requirement, excluding the additional expense related to the surcharge and

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[26] Direct Testimony of Venita McCellon-Allen at 57-58 (July 27, 2012).

[27] Direct Testimony of A. Malcolm Smoak at 11-17 (July 27, 2012); Direct Testimony of Charles D. Matthews at 29-30 (July 27, 2012).

[28] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 37364.

excluding the Company's requested increase, is significantly greater than the expense in 2010 and prior years, according to the Company's responses to Staff's RFI No. 1-14 and Staff's RFI No. 1-7, which provide a five year history of vegetation management expense for distribution and transmission, respectively.[29]

The base distribution vegetation management expense in 2011 was $4.689 million, which was $1.622 million (or 53%) greater than the same expense in 2010, and $2.504 million (or 115%) greater than the same expense in 2009, according to the Company's response to Staff's RFI No. 1-14.

The transmission vegetation management expense in 2011 was $3.2 million (total Company), which was $1.2 million (or 60%) greater than the same expense in 2010, and $1.2 million (or 60%) greater than the same expense in 2009, according to the Company's response to Staff's RFI No. 1-7.

Q. SHOULD THE COMMISSION INCREASE THE REVENUE REQUIREMENT TO PROVIDE ADDITIONAL FUNDING FOR VEGETATION MANAGEMENT BY $2.1 MILLION FOR DISTRIBUTION AND BY $0.4 MILLION FOR TRANSMISSION?

A. No. First, unlike the amounts authorized via surcharge in the settlement in Docket No. 37364, if these additional amounts are included in the revenue requirement, there is no guarantee that the Company actually will spend these amounts for this purpose. The Company actually may spend less than it is authorized to recover because revenue dollars typically are not "painted" or reserved for specific expenses unless the Commission authorizes reserve accounting for the specific expenses. In my experience, utilities have

[29] Attachments 10 and 11 (SWEPCO's Response to Staff's RFI Nos. 1-14 and 1-7).

significant discretion over the actual spending on activities such as vegetation management and often reduce the expenses between rate cases.

Second, the Company has not provided any cost/benefit analyses to justify the additional expenses. Its request is based on nothing more than the claim that it will spend more on vegetation management if it is allowed an additional amount for that purpose in its revenue requirement.

Third, the Company failed to address or reflect any reductions in maintenance expense for reductions in outages and other maintenance activities due to the additional trimming activities. In other words, if there actually is a cost benefit to additional trimming activities, then the activities should be largely self-financing through reductions in maintenance expense over several years. If this is not the case, then there is no business case for the additional trimming activities and the related expenses sought by the Company.

Fourth, the test year already includes huge increases in vegetation management expenses compared to 2010: $1.6 million for distribution and $0.4 million for transmission (total Company increase times 38% Texas retail jurisdictional factor), or 54% on a combined basis. Cities do not oppose these huge increases in the test year. However, the actual test year increases alone going forward should be sufficient to substantially increase trimming activities compared to prior years, without the additional increases under the Company's proposed adjustments.

B. <u>Reduce Turk Projected Operation and Maintenance Expenses</u>

Q. PLEASE DESCRIBE THE COMPANY'S REQUEST FOR TURK NON-FUEL OPERATION AND MAINTENANCE EXPENSES.

A. The Company requests $17.619 million (total Company) for its ownership share of the Turk plant non-fuel O&M expenses, according to Mr. Franklin's Exhibit PWF-5. The Company estimates the total Turk plant O&M expense before allocations to other owners at $24.026 million, also according to Mr. Franklin's Exhibit PWF-5. These amounts do not include non-fuel O&M expense for fuel and consumable handling expenses, according to the Company's response to Staff's RFI No. 19-7.[30]

Due to a lack of actual operating experience with Turk, the Company's request is based on an estimate that it developed using expenses for the Pirkey and Oklaunion plants, according to Mr. Franklin.[31] Mr. Franklin described this process as follows:

> This budget was developed mainly by leveraging SWEPCO's operational knowledge of the Pirkey and Oklaunion (which is owned by Public Service Company of Oklahoma, a SWEPCO affiliate) Power Plants. Both the Pirkey and Oklaunion Plants are solid-fueled, single-unit generating stations that are retrofitted with FGD systems. Adjustments were made to existing plant O&M values to account for differences in fuel, major equipment, and operational conditions.[32]

The Company provided additional information regarding the components of its proposed Turk O&M expense in response to Staff's RFI No. 19-7, including projections for years beyond 2013.

Q. HOW DOES THE COMPANY'S REQUEST COMPARE TO THE O&M EXPENSE INCURRED AT THE COMPANY'S OTHER SOLID-FUEL POWER PLANTS?

A. It is significantly higher in absolute dollars and on a dollars per MW basis, except for its share of the Dolet Hills plant. The Company's request is $17.619 million for its 440 MW

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[30] Attachment 12 (SWEPCO's Response to Staff's RFI No. 19-7).

[31] Direct Testimony of Paul W. Franklin at 40 (July 27, 2012).

[32] *Id.*

share of the Turk plant, or $40 per MW. By contrast, the Company's non-fuel O&M expense in 2011 for the Welsh plant was $24 per MW, for the Flint Creek plant was $27 per MW, for the Pirkey plant was $36 per MW, and for the Dolet Hills plant was $57 per MW, according to the information for these plants in the Company's 2011 FERC Form No. 1.[33]

Q. HOW DOES THE COMPANY'S REQUEST COMPARE TO THE O&M EXPENSE INCURRED AT THE TRIMBLE 2 UNIT, A NEW COAL-FIRED PLANT THAT WENT INTO SERVICE IN KENTUCKY IN 2011?

A. It is significantly higher in absolute dollars and on a dollars per MW basis than Trimble Country 2 ("TC2"). TC2 is a supercritical coal-fired unit that went into service in January 2011. It has a scrubber and a selective catalytic converter, similar to the Turk plant. TC2 is a 616 MW plant, according to the Kentucky Utilities Company FERC Form No. 1 for 2011.[34] The TC2 non-fuel O&M expense for 2011 was $14.112 million, or $22.91 per MW.[35] The TC2 non-fuel O&M expense for the 12 months ending March 31, 2012 was $14.227 million, or $23.10 per MW, according to discovery obtained in a recent rate proceeding involving the two owners of the plant, Kentucky Utilities Company and Louisville Electric and Gas Company.[36] I was personally involved in that rate proceeding.

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[33] Attachment 13 (SWEPCO 2011 FERC Form No. 1, pages 402.1 and 403.1 with Kollen handwritten totals and calculations).

[34] Attachment 14.

[35] *Id.*

[36] Attachment 15 (*Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*, Kentucky Public Service Commission, Case No. 2012-00221, Kentucky Utilities Company Response to Kentucky Industrial Utility Customers, Inc. Data Request No. 1-23).

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend a reduction of 25% from the Company's requested amount for several reasons. First, the Company's estimate is not known and measurable; it is an estimate. At a minimum, the estimate must be reasonable and the best way to assess whether it is reasonable is through comparisons to other similar plants. Second, the Company's estimate is based on the Pirkey plant, which is a lignite plant and one of the Company's highest cost solid-fuel plants. At least on the surface, it is not reasonable to use the costs for a lignite plant as a proxy for a coal-fired plant. Third, the TC2 plant is a closer match to the Turk plant than any of the Company's other plants that it operates and maintains, particularly the Pirkey lignite plant. Even with the environmental controls on TC2, that plant operates at a lower cost than any of the Company's plants, including the Company's uncontrolled (for environmental purposes) and low-cost Welsh and Flint Creek coal-fired plants.

Q. HAVE YOU QUANTIFIED THE EFFECT OF YOUR RECOMMENDATION?

A. Yes. The 25% reduction results in a reduction in the Company's requested O&M expense of $4.405 million (total Company) to $13.214 million (total Company), or $30.03 per MW, which is still 30% more than the actual TC2 plant O&M expense, and is close to the average of the Company's other solid-fuel plants – Pirkey, Welsh, and Flint Creek. The 25% reduction results in a reduction in the Company's requested O&M expense of $1.439 million (Texas retail) and $1.489 million in the revenue requirement. I used a Texas retail jurisdictional factor of 32.67% as shown on Ms. Meyers' Exhibit BFM-2 for the Turk plant O&M expense.

C. Reduce Abnormally High Obsolete Inventory Expense to Reflect Five Year Average

Q. PLEASE DESCRIBE THE OBSOLETE INVENTORY EXPENSE WRITE-OFF IN THE TEST YEAR.

A. The Company expensed $1.041 million (total Company) in obsolete inventory in the test year, according to Schedule E-1.2 page 5 of 5, which the Company confirmed in response to Staff's RFI No. 6-2.[37]

Q. HOW DOES THE OBSOLETE INVENTORY EXPENSE WRITE-OFF IN THE TEST YEAR COMPARE TO PRIOR YEARS?

A. It is substantially more than in the prior four years, according to the Company's response to Staff's RFI No. 6-3.[38] The Company wrote-off $0.666 million (total Company) in 2007, $0.750 million (total Company) in 2008, $0.377 million (total Company) in 2009, and $0.844 million (total Company) in 2010. The average write-off over the five year period, 2007-2011, was $0.736 million (total Company).

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission use a five-year average to determine the reasonable level of this expense. It is obvious that the test year expense was unusually high and should be adjusted to a normal level. The five-year average provides a normal level.

Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION?

A. The effect is a reduction in the obsolete inventory expense of $0.105 million on a Texas retail basis. The calculations of the five-year average, the Texas jurisdictional amount,

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[37] Attachment 47 (SWEPCO's Response to Staff's RFI No. 6-2).

[38] Attachment 16 (SWEPCO's Response to Staff's RFI No. 6-3).

and the revenue requirement effect of $0.108 million are shown in the Summary Table and on Schedule LK-5.

D. Reduce Injuries and Damages Expense to Remove Nonrecurring Settlement Expenses

Q. PLEASE DESCRIBE THE INJURIES AND DAMAGES EXPENSE IN THE TEST YEAR.

A. The Company expensed $4.544 million (total Company) in injuries and damages expense in the test year, according to the Company's response to Staff's RFI No. 4-49.[39] The Company adjusted the per books amount to $4.540 million (total Company).

Q. HOW DOES THE INJURIES AND DAMAGES EXPENSE IN THE TEST YEAR COMPARE TO PRIOR YEARS?

A. It is substantially more than in the prior three years, according to the Company's response to Staff's RFI No. 4-49. The Company expensed $2.594 million (total Company) in 2008, $2.623million (total Company) in 2009, and $3.299 million (total Company) in 2010.

Q. WHY DID THE EXPENSE INCREASE IN THE TEST YEAR COMPARED TO PRIOR YEARS?

A. One reason is that the Company settled lawsuits and included the settlement costs in the test year expense, according to the response to Staff's RFI No. 4-50.[40] The Company provided the settlement costs and a description of the settlements in the Highly Sensitive response to Staff's RFI No. 4-75.[41]

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[39] Attachment 17 (SWEPCO's Response to Staff's RFI No. 4-49).

[40] Attachment 18 (SWEPCO's Response to Staff's RFI No. 4-50).

[41] Attachment 19 (SWEPCO's Response to Staff's RFI No. 4-75, Redacted).

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission exclude the settlement costs from the test year. These were nonrecurring expenses. I note that the Company itself excluded the costs of a "non-recurring legal contingency" from miscellaneous general expenses, account 9302, according to Mr. Hamlett, which the Company confirmed in its response to Staff's RFI No. 4-52.[42] Thus, my recommendation is consistent with the Company's other adjustment to remove nonrecurring expenses of a similar nature.

Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION?

A. Cities have reflected the CARD adjustment to normalize injuries and damages expense over five years. This adjustment still includes one-fifth of the settlement costs incurred in the test year. If the settlement costs were removed from the test year, it would result in a reduction in the injuries and damages expense of $0.185 million on a Texas retail basis, or a reduction in the revenue requirement of $0.192 million. Thus, the amount that still remains in the injuries and damages expense for the settlement costs is $0.037 million and in the revenue requirement is $0.038 million. Consequently, I show the incremental reduction of $0.038 million in the Summary Table in my testimony. If the Commission does not adopt CARD's adjustment, but decides to remove the settlement costs from the test year, then the reduction in injuries and damages expense should be $0.187 million and the reduction in the revenue requirement should be $0.192 million. The total Company amount, the calculation of the Texas jurisdictional amount, the calculation of the revenue requirement effect of $0.192 million, and the calculation of the $0.038 million are shown on the Highly Sensitive Schedule LK-6.

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42 Attachment 20 (SWEPCO's Response to Staff's RFI No. 4-52); Direct Testimony of Randall W. Hamlett at 27 (July 27, 2012).

E. Reject Proposal to Recover Remaining Hurricanes Gustav and Ike Storm Costs on Recurring Basis Using 12 Month Amortization Period

Q. PLEASE DESCRIBE THE COMPANY'S REQUEST TO RECOVER THE REMAINING UNAMORTIZED AMOUNT OF DEFERRED HURRICANES GUSTAV AND IKE COSTS.

A. The Company proposes to recover the unamortized cost remaining at December 31, 2012, as a recurring annual expense even though it will be fully recovered by April 2013. Mr. Hamlett describes the Company's proposal.[43] The Company was authorized to defer \$3.6 million for these storms in the settlement in Docket No. 37364. It was also authorized to amortize the \$3.6 million over 36 months, or \$0.100 million per month. At the end of the test year, the Company had remaining \$1.2 million, and it projects that at December 31, 2012, it will have \$0.4 million, left to amortize. The Company's calculations are shown on Schedule A-3 Adjustment 22 and Schedule G-11, although it should be noted that there appears to be a typographical error on Schedule G-11 because it shows an amortization expense of \$0.5 million instead of \$0.4 million.

Q. WHAT WILL BE THE EFFECT OF THE COMPANY'S PROPOSAL IF IT IS NOT MODIFIED?

A. The Company will recover \$0.4 million each year until its base rates are again reset. If that is four years into the future, then the Company will recover \$1.6 million, or \$1.2 million more than the remaining unamortized cost at December 31, 2012.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission assume another 36-month amortization period to avoid the circumstance where the Company recovers multiple times its actual

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[43] Direct Testimony of Randall W. Hamlett at 28-29 (July 27, 2012).

unamortized costs remaining at December 31, 2012. My recommendation assumes that the Company's base rates will be reset again at or after the end of the 36-month period.

Q. HAVE YOU QUANTIFIED THE EFFECT OF YOUR RECOMMENDATION ON THE COMPANY'S REVENUE REQUIREMENT?

A. Yes. The effect is a reduction in amortization expense of $0.267 million and a reduction in the revenue requirement of $0.276 million. I provide the calculations on Schedule LK-7.

F. <u>Depreciation Issues Should be Considered Within Context of Significant Depreciation Reserve Surplus</u>

Q. WHAT IS THE STATUS OF THE COMPANY'S ACCUMULATED DEPRECIATION RESERVE BASED ON THE PARAMETERS THAT IT PROPOSES IN THIS PROCEEDING?

A. The Company has a theoretical reserve surplus of $608 million on a total Company basis, meaning that it actually has recorded and recovered $608 million more through the December 31, 2011 study date than it should have based on the parameters that it proposes in this proceeding. The theoretical reserve surplus would be even greater than calculated by the Company if certain of the parameters are revised as Cities recommends, such as the life spans for Turk and Stall and the dismantling costs for the production plant accounts.

The Company provided the theoretical depreciation reserve that it calculated on Mr. Davis' Exhibit DAD-1 pages 16-18 in column VI entitled "Calculated Depreciation Requirement." The actual depreciation reserve is shown on the same pages in column VII entitled "Allocated Accumulated Depreciation." On page 18, the total Company ***theoretical*** depreciation reserve is $1,731.776 million and the total Company ***actual*** depreciation reserve is $2,339.517 million. The total Company actual depreciation reserve exceeds the theoretical depreciation reserve by $608 million reserve surplus, or 35%, for all functions. On a functional basis, the total Company depreciation reserve surplus is $134.832 million for production plant, $129.331 million for transmission plant, and $345.355 million for distribution plant.

The Company confirmed in response to TIEC's RFI No. 2-1 that the difference between the amounts on Exhibit DAD-1 pages 1-18 in columns VI and VII does, in fact, represent the depreciation reserve surplus.[44] In its response to TIEC's RFI No. 2-1, the Company defined the "theoretical reserve" shown in column VI as "the calculated balance that would be in accumulated depreciation account at December 31, 2011 using current depreciation study parameters such as average service life and net salvage."[45] The Company provided the workpapers used to calculate the theoretical depreciation reserves for the production plant accounts in response to Staff's RFI No. 3-1.[46] The theoretical depreciation reserves for the other functional plant accounts were calculated in the Company's PowerPlant software, according to its response to TIEC's RFI No. 2-1.[47]

Q. WHAT IS THE SIGNIFICANCE OF THE DEPRECIATION RESERVE SURPLUS IN THIS PROCEEDING?

A. This surplus represents overrecoveries from customers in prior years due to excessive depreciation rates in those prior years compared to depreciation rates based on present

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44 Attachment 21 (SWEPCO's Response to TIEC's RFI No. 2-1).

45 *Id.*

46 Attachment 22 (SWEPCO's Response to Staff's RFI No. 3-1, excerpt from depreciation workpapers – Theoretical Reserve).

47 Attachment 21 (SWEPCO's Response to TIEC's RFI No. 2-1).

parameters, such as the estimated life spans for the production plant accounts, among others. In other words, the estimated life spans or average service lives for production, transmission, and distribution plant were too short in prior years based on actual experience and present projections. The surplus would be even greater if the Company had reflected the appropriate life spans for the Welsh 2, Dolet Hills, and Stall plants in its proposed depreciation rate calculations rather than the unduly short life spans it assumed for those plants.

The existence and the sheer magnitude of the depreciation reserve surplus as of December 31, 2011, should cause the Commission to closely review, and exercise extreme caution in adopting, the parameters proposed by the Company in this proceeding. Many of these parameters inordinately increase the depreciation rates in the near-term. Any excessive depreciation rates in this proceeding will have the effect of further increasing the depreciation reserve surplus, not reducing it. For example, as I discuss later, the Company proposes a life span of 40 years for the Turk plant. However, that life span is arbitrarily low compared to AEP's standard life span of 60 years for its coal-fired plants. The fact is that AEP has operated or plans to operate nearly all of its coal-fired plants for at least 60 years. If the Commission adopts the Company's proposed 40-year life span for Turk in this proceeding and 20 years from now adopts depreciation rates that reflect the 60-year life span, then the Company's customers will have overpaid for the first 20 years and customers thereafter will underpay for the next 40 years. This results in intergenerational inequities that easily can and should be avoided.

In other words, the depreciation parameters have real-world consequences on the rates customers pay today and the rates they will pay in the future. There are valid concerns regarding intergenerational equities. Given the huge depreciation reserve surplus, if there is any question regarding whether a shorter or longer life span should be used, then the Commission should use the longer life span, not the shorter. Further, the Company's history has been to argue initially for shorter life spans and then propose longer life spans after it has recovered a significant amount of the plant's costs in its early years of operation, and then only after it becomes inescapably evident that it will not remove the plant from operation or retire it on the original schedule.

G. Reject Proposals to Retire Welsh 2 Without Further Study and Accelerate Recovery of Undepreciated Costs

Q. **PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO REMOVE WELSH 2 FROM SERVICE SOMETIME BETWEEN 2014 AND 2016 AND RETIRE THE UNIT, RATHER THAN RETROFITTING IT WITH ENVIRONMENTAL CONTROLS AND CONTINUING TO OPERATE IT.**

A. The Company plans to remove Welsh 2 from service on December 31, 2014 and retire the unit, according to Ms. McCellon-Allen.[48] Ms. McCellon-Allen claims that the Company determined that the cost of environmental retrofits for Welsh 2 "was not financially feasible for our customers or shareholders."[49] Ms. McCellon-Allen asserts that the cost to retrofit the unit would be $529 million.[50]

In addition, the Company entered into a settlement agreement related to the construction of the Turk plant with the Sierra Club, National Audubon Society, and Audubon Arkansas that requires it "to seek regulatory approval to retire Welsh Unit 2 no later than December 31, 2014, (or 2016 if additional time is needed to complete

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[48] Direct Testimony of Venita McCellon-Allen at 39 (July 27, 2012).

[49] *Id.*

[50] *Id.*

transmission mitigation work.)"[51] Ms. McCellon-Allen states that the Sierra Club settlement "did no more than confirm, in the context of that settlement, what SWEPCO had already determined was a necessary course of action."[52]

Q. DOES THE COMPANY PLAN TO SEEK COMMISSION APPROVAL TO REMOVE WELSH 2 FROM SERVICE AND RETIRE THE UNIT?

A. No. The settlement agreement with the Sierra Club, National Audubon Society, and Audubon Arkansas requires the Company to seek regulatory approval to retire Welsh Unit 2. In Cities' RFI No. 5-7, the Company was asked to describe its specific "plans to seek regulatory approval to retire Welsh 2, including the specific regulatory agencies from which it will seek such approval, and the specific approvals the Company will seek from each agency."[53] The Company responded that it "has not yet determined what, if any, regulatory approval will be necessary other than providing notification to the Southwest Power Pool (SPP)."[54] In other words, the Company does not believe that it is necessary to seek the Commission's approval to remove Welsh 2 from service and retire the unit.

In CARD's RFI No. 2-27, the Company was asked to "identify the necessary regulatory approvals and transmission mitigation measures for permanent retirement of Welsh 2."[55] The Company responded that "SWEPCO does not require any regulatory approvals in order to retire Welsh Unit 2."[56]

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[51] *Id.* at 32-33.

[52] *Id.* at 39.

[53] Attachment 23 (SWEPCO's Response to Cities' RFI No. 5-7).

[54] *Id.*

[55] Attachment 24 (SWEPCO's Response to CARD's RFI No. 2-27).

[56] *Id.*

Q. WHY IS THIS SIGNIFICANT?

A. There are several reasons. The first and most important is that the Company has made a unilateral decision to retire Welsh 2 and it intends to do so without Commission review or authorization. The Commission cannot realistically and comprehensively review the implications of the loss of Welsh 2 and the replacement of the capacity and related energy compared to the retrofit and continued operation of the unit in this rate proceeding.

Second, the Commission has not had an opportunity to assess whether the retirement of Welsh 2 and replacement of the Welsh 2 capacity and energy is the least cost option. Realistically, this assessment cannot be performed within the context of a rate case, such as this proceeding. The Welsh 2 unit provides 528 MW of capacity. The Company's share of the Turk plant provides only 440 MW of capacity. The retirement of Welsh 2 also places the Company in a reserve margin deficiency in 2016, according to its response to TIEC's RFI No. 6-4.[57] Thus, in order to meet its reserve margin requirement, the Company will have to build or otherwise acquire additional capacity.

Third, this unilateral decision will impose significant costs on customers. The low-cost Welsh 2 unit was sacrificed to ensure the completion and operation of the Turk plant. Nearly three years ago, the Company estimated the cost to retrofit Welsh 2 at $529 million. The certification cost of the Company's share of the Turk plant is nearly three times that amount, excluding AFUDC and excluding the cost of the transmission facilities. That is a poor tradeoff in and of itself. However, the sacrifice of Welsh 2 to complete the Turk plant will impose additional costs on customers from another new power plant or the purchase of firm capacity.

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[57] Attachment 25 (SWEPCO's Response to TIEC's RFI No. 6-4).

Fourth, the studies the Company used to assess whether Welsh 2 should be retired do not reflect the impact from the D.C. Circuit Court decision earlier this year in which it vacated the Cross-State Air Pollution Rule ("CSAPR"). Despite the significance of this issue, the Company "has not yet completed any resource planning studies that reflect the vacatur of the CSAPR rule by the D.C. Circuit Court," according to its response to Cities' RFI No. 5-2.[58] The Company's most recent economic study considered in its decision to retire Welsh 2 was performed in early 2010, or nearly three years ago, according to its response to CARD's RFI No. 1-41.[59] It is incomprehensible that the Company would move ahead with the retirement of Welsh 2 without adequate study of the effect of the D.C. Circuit Court action.

Fifth, the Company has developed a list of environmental compliance projects and the estimated costs for Welsh 1 and 3, which it provided in response to CARD's RFI No. 1-38.[60] Similar projects would be undertaken for Welsh 2 if it is not retired in 2014, according to the Company's response to CARD's RFI No. 2-28.[61] The Company estimates that the cost of environmental compliance for both Welsh 1 and 3 will be $520.063 million, according to Attachment 1 to the response to CARD's RFI No. 1-38.[62] In other words, the cost to retrofit a single Welsh unit would be only $260 million, or one half of the $529 million cited by the Company for Welsh 2 based on an analysis nearly three years old that was prepared before the vacatur of the CSAPR rule. Clearly, the retirement of Welsh 2 needs to be revisited based on current information and on the

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58 Attachment 26 (SWEPCO's Response to Cities' RFI No. 5-2).

59 Attachment 27 (SWEPCO's Response to CARD's RFI No. 1-41).

60 Attachment 28 (SWEPCO's Response to CARD's RFI No. 1-38).

61 Attachment 29 (SWEPCO's Response to CARD's RFI No. 2-28).

62 Attachment 28 (SWEPCO's Response to CARD's RFI No. 1-38).

Company's more recent estimate of the requirements and costs to retrofit the Welsh units.

Sixth, the Company based its depreciation request for the Welsh plant on the assumption that Welsh 2 will be retired in mid-2016 instead of in 2040, the year that it would be retired if a life span of 60 years is used. This is approximately midway between the probable retirement dates that the Company proposes for Welsh 1 and Welsh 3, using life spans of 60 years. In other words, the Company's depreciation request incorporates an accelerated recovery of the remaining Welsh 2 undepreciated plant costs over the next 4.5 years.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSAL TO REMOVE WELSH 2 FROM SERVICE AND RETIRE IT IN 2014 OR NO LATER THAN 2016?

A. I recommend that the Commission initiate a separate proceeding to consider the retirement of Welsh 2 in 2016 along with the Company's plans to replace the Welsh 2 capacity. The Commission should exercise its authority to ensure that customers are not harmed by the Company's unilateral decision to prematurely retire this unit and incur the costs to replace the capacity and the cost of transmission upgrades.

Alternatively and at a minimum, if the Company proceeds with the retirement of Welsh 2, the Commission should consider reducing the Turk plant costs by the remaining undepreciated Welsh 2 plant costs, and do so in this rate proceeding. This will reduce the Turk rate base and the Turk capital-related expense amounts included in the revenue requirement.

Q. PLEASE DESCRIBE MORE SPECIFICALLY THE COMPANY'S PROPOSAL TO ACCELERATE THE RECOVERY OF THE WELSH 2 UNDEPRECIATED PLANT COSTS OVER A 4.5 YEAR PERIOD.

A. In its depreciation study, the Company developed an average service life for the Welsh plant, consisting of all three units, with the assumptions that Unit 2 would be retired in mid-2016, Unit 1 would be retired in mid-2037, and Unit 3 would be retired in mid-2042. The Company's assumptions and the calculations of the average remaining service life for the Welsh plant are detailed on Mr. Davis' Exhibit DAD-2 pages 124-129. The Excel workpapers providing these calculations were provided in response to Staff's RFI No. 3-1.[63] It is reasonable to assume that if Welsh 2 were retrofitted in the same manner that the Company plans to retrofit Welsh 1 and 3, that it would remain in service beyond 2016 and instead be retired at some date between the probable retirement dates for Welsh 1 and 3 in 2037 and 2042, respectively.

Q. SHOULD THE COMMISSION ALLOW THE COMPANY ACCELERATED RECOVERY OF THE WELSH 2 UNDEPRECIATED PLANT COSTS?

A. No. First, I recommend that the Commission direct the Company to defer its plans to retire the unit until the Commission can conduct a detailed and comprehensive review of the Company's options in a separate proceeding. Second, the Commission should reject, at least for purposes of the depreciation rates set in this proceeding, the Company's assumption that it will retire the unit in 2016. Instead, the Commission should assume that the unit will continue operating and that it will be retired in 2040 after a 60 year life

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[63] Attachment 30 (SWEPCO's Response to Staff's RFI No. 3-1, excerpt from depreciation workpapers - Welsh Service Life).

span, which is consistent with the life span parameters for Welsh 1 and 3 and their probable retirement dates in 2037 and 2042, respectively.

Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION TO USE A PROBABLE RETIREMENT DATE OF 2040 FOR WELSH 2 RATHER THAN THE 2016 DATE PROPOSED BY THE COMPANY?

A. The effect is a reduction in depreciation expense of $1.042 million and a reduction in the revenue requirement of $1.079 million. The calculations are detailed on Schedule LK-8. I used the Company's Excel workpapers to compute the Welsh plant average remaining service lives by plant account, but moved the Company's retirement dollars for Welsh 2 from 2016 to 2040 in each plant account. I then recalculated the Welsh plant depreciation rates using the corrected remaining service life for each plant account.

H. Reject Proposal to Shorten Dolet Hills Life Span from 60 Years, Approved Only Three Years Ago, to an Arbitrary 40 Years

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO SHORTEN THE SERVICE LIFE FOR DOLET HILLS FROM 60 YEARS TO 40 YEARS.

A. The Company proposes to shorten the life span for Dolet Hills from the 60 years that it proposed and the Commission adopted in Docket No. 37364, only three years ago, to 40 years. This proposal significantly shortens the remaining life and advances the probable retirement date to 2026 from 2046, even as SWEPCO and Cleco, the co-owner of the plant, plan to spend significant amounts to retrofit the plant to meet environmental compliance requirements, according to the response to TIEC's RFI No. 5-9.[64] In fact, as would be expected, the economic analysis provided in response to TIEC's RFI No. 5-9

[64] Attachment 31 (SWEPCO's Response to TIEC's RFI No. 5-9), and Attachment 32 (SWEPCO's Response to TIEC's RFI No. 5-9, Confidential Attachment 1).

extends well beyond the 2026 date the Company now proposes as the basis for its 40-year life span parameter.

Q. PLEASE DESCRIBE THE BASIS FOR THE 60-YEAR LIFE SPAN ADVOCATED BY THE COMPANY IN DOCKET NO. 37364, ITS LAST BASE RATE PROCEEDING.

A. In the prior proceeding (filed in August 2009), Company witness Mr. David Davis stated that "[f]or Production Plant, the generating unit retirement dates and the interim retirement history for the individual plant accounts were used to determine the average service lives and the remaining lives of the plants. The AEPSC Fossil & Hydro Generation Asset & Outage Planning Department provided the generating unit retirement dates used in the life-span analysis."[65] In the depreciation study attached to Mr. Davis' Direct Testimony as Exhibit DAD-1 page 8, Mr. Davis stated that "American Electric Power Service Corporation provided the retirement dates used in the life-span analysis. The retirement dates for the generating plants are shown on Schedule IV in this report."[66] On Schedule I of the depreciation study, the "Terminal Retirement Date" for Dolet Hills is shown as 2046, which reflects a 60-year life span.[67] On Schedule IV of the depreciation study, entitled "Generating Unit Retirement Dates," the retirement date for Dolet Hills is shown as 2046 and the life span is shown as 60 years.[68]

Also in the prior proceeding, Company witness Mr. Paul Franklin stated that "SWEPCO's coal and lignite-fired power plants have an expected useful life of 60 years. This expected service life is based on the expected life of major equipment, such as the

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[65] Attachment 33 (Docket No. 37364, Direct Testimony of David A. Davis at 9 (Aug. 28, 2009)).

[66] Attachment 34.

[67] Attachment 35.

[68] Attachment 36.

steam generator, and also based on AEP's historical operating experience with similar plants."[69]

Q. WHAT IS THE BASIS FOR THE COMPANY'S PROPOSAL TO SHORTEN THE LIFE SPAN TO 40 YEARS IN THIS PROCEEDING?

A. The Company claims that it and AEPSC personnel have reevaluated the expected retirement date for its generation plant. Mr. Davis states that "[f]or Production Plant, the generating unit retirement dates and the interim retirement history for the individual plant accounts were used to determine the average service lives and the remaining lives of each specific account at each plant."[70] In the depreciation study attached to Mr. Davis' Direct Testimony as Exhibit DAD-1, Mr. Davis states that "SWEPCO and American Electric Power Service Corporation (AEPSC) personnel provided the retirement dates used in the life-span analysis for Production Plant."[71] Mr. Davis states further:

> Since SWEPCO's last depreciation study (property investment dated December 31, 2007), SWEPCO and AEPSC personnel have reevaluated the expected retirement dates for its generation plant including Welsh Plant Unit 2 and Dolet Hills Unit 1. The reevaluation for these two units indicated that Welsh Unit 2's estimated retirement date should be 24 years earlier (2016) than previously estimated (2040) and that Dolet Hills Unit 1's estimated retirement date should be 20 years earlier (2026) than previously estimated (2046). Reasons for the earlier Welsh Unit 2 retirement date and the earlier Dolet Hills retirement date are discussed by SWEPCO witness Paul Franklin in his testimony.[72]

Mr. Franklin states that "[t]he 40-year life for the Dolet Hills Plant is based on CLECO's evaluation of the useful life of the plant. CLECO has the responsibility for

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69 Attachment 37 (Docket No. 37364, Direct Testimony of Paul W. Franklin at 29 (Aug. 28, 2009)).

70 Direct Testimony of David A. Davis at 10 (July 27, 2012).

71 Direct Testimony of David A. Davis, Exhibit DAD-1 at 7 (July 27, 2012).

72 *Id.*

operating and maintaining the plant. It therefore is prudent for SWEPCO to rely on CLECO for this type of projected life information."[73]

Q. DID THE COMPANY OFFER ANOTHER EXPLANATION IN RESPONSE TO DISCOVERY?

A. Yes. In TIEC's RFI No. 2-10, the Company was asked to explain why it proposed to shorten the life of the Dolet Hills plant from a 60-year life proposed in Docket No. 37364 to 40 years in this proceeding.[74] In response to this request, the Company claims that "[t]he decision to use a projected life of 60 years in Docket No. 37364 was made in error."[75]

Q. WAS THE 60 YEAR LIFE IN DOCKET NO. 37364 AN "ERROR"?

A. No. The 60-year life span parameter in Docket No. 37364 was no scrivener's "error," where the probable retirement year was input incorrectly as 2046 rather than 2026. This was a specific depreciation parameter evaluated and proposed by the Company and AEPSC only three years ago. The 60-year life span parameter also was no scrivener's error when the Company proposed the same 60 years for Dolet Hills in Docket No. 09-008-U before the Arkansas Public Service Commission ("APSC") in 2009. Similar to its testimony before this Commission, in Arkansas the Company supported the 60-year life span through the testimony of Mr. Davis.[76] Similar to this Commission, the APSC adopted the 60-year life span for the Dolet Hills depreciation rates, according to the Company's response to TIEC's RFI No. 3-4.[77]

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73 Direct Testimony of Paul W. Franklin at 18 (July 27, 2012).

74 Attachment 38 (SWEPCO's Response to TIEC's RFI No. 2-10).

75 *Id.*

76 Attachment 39.

77 Attachment 40 (SWEPCO's Response to TIEC's RFI No. 3-4).