

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF)
OKLAHOMA GAS AND ELECTRIC COMPANY)
FOR AN ORDER OF THE COMMISSION)
AUTHORIZING APPLICANT TO MODIFY ITS)
RATES, CHARGES, AND TARIFFS FOR RETAIL)
ELECTRIC SERVICE IN OKLAHOMA)

CAUSE NO. PUD 201700496

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CORPORATION COMMISSION
OF OKLAHOMA

RESPONSIVE TESTIMONY

OF

WILLIAM W. DUNKEL

ON BEHALF OF

MIKE HUNTER,

OKLAHOMA ATTORNEY GENERAL

May 2, 2018

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I. INTRODUCTION

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William W. Dunkel. My business address is 8625 Farmington Cemetery Road, Pleasant Plains, Illinois 62677.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE INCLUDING A LIST OF PRIOR REGULATORY PROCEEDINGS IN WHICH YOU HAVE TESTIFIED?

A. Yes. Exhibit WWD-1 is a summary of my qualifications, experience, and a list of prior testimonies before state utility regulatory agencies. As shown on that exhibit, I have extensive experience in numerous jurisdictions addressing utility depreciation rates, including my testimony on depreciation rates before this Commission in the recent PSO proceeding, Cause No. PUD 201700151.

Q. COULD YOU DESCRIBE YOUR UTILITY REGULATION CONSULTING FIRM?

A. Yes. My firm frequently participates on behalf of state utility regulatory commissions or their staff. For example, over the past five years, 60 percent of my firm's cases have been on behalf of state utility regulatory commissions, their staff, or administrative law judges. As a frequent commission staff witness, I understand that proper depreciation rates should be fair to all parties, including investors, current ratepayers, and future ratepayers. I have incorporated this concept of fairness into my recommendations in this proceeding.

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

A. I am testifying on behalf of Mike Hunter, Oklahoma Attorney General.

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

2 A. The primary purpose of my testimony is to determine and recommend appropriate
3 depreciation accrual rates for Oklahoma Gas and Electric Company of Oklahoma (“OGE”).
4 This includes addressing the decommissioning cost estimates that are used in determining
5 the depreciation accrual rates.

6 **Q. DID YOU PARTICIPATE IN A FIELD VISIT OF SOME OF OGE’S FACILITIES
7 IN OKLAHOMA?**

8 A. Yes. On March 27 and 28, 2018, I participated in a field visit to some of OGE’s facilities
9 located in Oklahoma. As requested, Company personnel were made available to discuss
10 OGE’s operations and facilities.

11 **II. CREDIBILITY ISSUES IN THE OGE DEPRECIATION STUDY**

12 **Q. COULD YOU DESCRIBE ANY CONCERNS YOU HAVE WITH THE
13 CREDIBILITY OF OGE’S DEPRECIATION STUDY?**

14 A. Yes. A major depreciation issue in this proceeding is the credibility and weight to be given
15 to the OGE depreciation study. The OGE depreciation study was prepared by John J.
16 Spanos from the firm Gannett Fleming. The Oklahoma Corporation Commission
17 (“Commission”) properly rejected Mr. Spanos’s depreciation study in the recent PSO
18 proceeding and found that Mr. Spanos had “altered the data” and that there were other
19 “irregularities.” The Commission adopted the Report and Recommendation of the
20 Administrative Law Judge with a few modifications. The Commission adopted the
21 following findings:

22 105. THE COMMISSION FURTHER FINDS that it is clear that PSO’s
23 witness Mr. Spanos made changes to the historic data in Account 367 and

1 did not disclose these unusual changes. It is also clear that Mr. Spanos did
2 not disclose that he had *altered the data* until the Attorney General had
3 discovered the alteration and asked about it in discovery. The record shows
4 that the difference between a 65 year average service life, which is what Mr.
5 Spanos recommended in the prior case *before altering the data*, and the 45
6 year average service life Mr. Spanos recommends in this case after altering
7 the data, is in excess of \$4 million per year. Additionally, there were
8 irregularities in Mr. Spanos's cited rates approved in prior proceedings as
9 well as the industry range of lives used.

10 106. THE COMMISSION FURTHER FINDS that the *depreciation study*
11 *proposed by PSO is rejected*. Furthermore, the Commission adopts the
12 Attorney General's life and Iowa curve combination recommendations.¹

13 The depreciation study filed by OGE in this proceeding also contains altered data and
14 similar improprieties, as will be demonstrated.

15 **1. DOUBLE RECOVERY OF ASBESTOS REMEDIATION COSTS**

16 **Q. PLEASE SHOW WHAT OGE INCLUDED IN ITS PROPOSED DEPRECIATION**
17 **EXPENSE FOR STEAM PRODUCTION PLANT.**

18 **A.** The table below shows the depreciation expense OGE proposes for steam production plant.
19
20

¹ Final Order, Order No. 672,864, Attachment 1, at 28, *Pub. Serv. Co. of Okla. Rates & Charges for Elec. Serv.*, No. PUD 201700151 (Okla. Corp. Comm'n Jan. 31, 2017) (emphasis added) (citations omitted).

Table 1²

Acct	Plant	Pro Forma Adjusted Depreciable Plant In Service	Adjustment Add Back Transmission LSE WP B 3-12	Adjustment For Non- Depreciable Plant In Service	Pro Forma Adjusted Depreciable Plant In Service	Proposed Annual Rate	Proposed DD&A Expense
STEAM PRODUCTION							
310	Land & Land Rights	11,550,707	-	10,582,703	968,004	2.94%	28,459
311	Struct. & Improv.	272,004,315	-	-	272,004,315	2.60%	7,072,112
312	Boiler Plant Equip.	1,166,562,243	-	-	1,166,562,243	2.84%	33,130,368
314	Turbogenerator Units	439,595,384	-	-	439,595,384	3.74%	16,440,867
315	Accessory Electric Equip.	147,955,760	-	-	147,955,760	2.64%	3,906,032
316	Misc. Power Plant Equip.	35,835,834	-	-	35,835,834	3.74%	1,340,260
317	ARO Cost-Steam Prod.	11,527,006	-	-	11,527,006	10.61%	1,223,015
TOTAL STEAM PRODUCTION		\$ 2,085,031,249	\$ -	\$ 10,582,703	\$ 2,074,448,546		\$ 63,141,113

1 The Proposed Annual Rates shown in the first six lines are as proposed in Mr. Spanos’s
 2 Depreciation Study.³ These proposed rates include recovery of the Decommissioning Costs
 3 as estimated by Mr. Kopp. The last line, Account 317, is an additional annual cost for the
 4 Steam Production Asset Retirement Obligations (“AROs”). As is reasonable, ratepayers
 5 would be charged for both the AROs and separately for the depreciation expenses resulting
 6 from Mr. Spanos’s proposed depreciation rates.

7 **Q. DO THE STEAM PRODUCTION AROS INCLUDE FUTURE “ASBESTOS**
 8 **REMEDIAION” FOR THE STEAM PRODUCTION PLANTS?**

9 A. Yes. The vast majority of the steam production AROs are for future asbestos remediation
 10 of the Steam Production plants. In response to AG-OGE-6-1, OGE provided the amount of
 11 its ARO liability for asbestos remediation at the various power plant locations. For

² See OGE Application Package, Volume II, Schedule I-1-1 (Jan. 16, 2018).

³ Direct Test. of John J. Spanos on behalf of Oklahoma Gas and Electric Co., Ex. JJS-2, at VI-4–VI-5 (Jan. 16, 2018) [hereinafter “Spanos Direct”].

1 example, for the Mustang power plant, the asbestos remediation ARO liability is
2 \$6,135,476. I have attached the OGE response to AG-OGE-6-1 as Exhibit WWD-3.

3 **Q. DOES THE \$6,135,476 ASBESTOS REMEDIATION ARO LIABILITY INCLUDE**
4 **THE FUTURE REMOVAL OF ALL THE ASBESTOS AT THE MUSTANG**
5 **STEAM PRODUCTION PLANT?**

6 A. Yes. The Mustang ARO liability includes the removal of *all* the asbestos. In response to
7 AG-OGE-21-5, OGE stated:

8 The total asbestos removal estimate as of 2015 was \$5,658,000 when the
9 ARO was created. This estimate *included the removal of all asbestos* at the
10 Plant. Based on the accounting standards required from implementation of
11 SFAS 143 and FIN 47, in 2015 the liability began accreting monthly and as
12 of 12/31/2017 the liability balance was \$6,135,476 as shown in AG
13 6-1_Att.⁴

14 **Q. IN SPITE OF THE FACT THAT THE COST OF REMOVING ALL OF THE**
15 **ASBESTOS AT THE MUSTANG PLANT IS INCLUDED IN THE ARO, DID MR.**
16 **KOPP ALSO INCLUDE ASBESTOS REMOVAL IN THE MUSTANG**
17 **DECOMMISSIONING COST ESTIMATE?**

18 A. Yes. For convenient reference, I have attached Mr. Kopp's Decommissioning Cost
19 Summary for the Mustang steam production units as Exhibit WWD-5. As can be seen for
20 each unit, Mr. Kopp includes the cost of "Asbestos Removal." In total, he included
21 \$5,224,000 for Asbestos Removal for the Mustang steam production units.

⁴ OGE Response to AG-OGE-21-5, attached as Ex. WWD-4 (emphasis added).

1 **Q. WHAT PROBLEM HAVE YOU IDENTIFIED?**

2 A. In spite of the fact that the removal of *all* asbestos is included in the ratepayer-supported
3 AROs, Mr. Kopp also included the asbestos removal in his decommissioning cost
4 estimates. Those decommissioning cost estimates are included in Mr. Spanos’s calculation
5 of his proposed depreciation rates. As a result, OGE is proposing to double-recover these
6 asbestos remediation costs.

7 **Q. WHAT DO YOU RECOMMEND?**

8 A. I do not object to ratepayers being charged for asbestos removal. However, ratepayers
9 should not be double-charged for asbestos removal.⁵ I have excluded the asbestos removal
10 from my determination of the decommissioning costs for those production plants for which
11 the Company’s response to AG-OGE-6-1 shows that asbestos remediation is being
12 recovered through an ARO. These are the Sooner Power Plant, the Horseshoe Lake Power
13 Plant, the Muskogee Coal Power Plant, the Seminole Power Plant, and the Mustang Power
14 Plant. These asbestos removal costs would be recovered from the ratepayers through the
15 AROs.

16 **2. DOUBLE RECOVERY OF WIND FARM REMOVAL COSTS**

17 **Q. IS OGE ALSO PROPOSING TO DOUBLE-RECOVER THE COSTS OF**
18 **REMOVING WIND GENERATION FACILITIES?**

19 A. Yes. The table below shows the depreciation expense OGE proposed in its direct testimony
20 for Other Production, which includes wind generation facilities.⁶

⁵ “Double-charged” does not imply that the total charge was exactly equal to twice the appropriate charge. Rather, it means OGE has proposed to recover amounts for the same expense twice.

⁶ In his supplement testimony, Mr. Spanos stated he had corrected errors in the amount of book depreciation reserve used for various Other Production Accounts. This alters some of the Other Production proposed

Table 2⁷

Account	Plant	Pro Forma Adjusted Depreciable Plant In Service (\$)	Adjustment For Non- Depreciable Plant In Service (\$)	Pro Forma Adjusted Depreciable Plant In Service (\$)	Proposed Annual Rate	Proposed DD&A Expense (\$)
OTHER PRODUCTION						
340	Land & Land Rights	1,185,111	1,185,111	-	0.00%	-
341	Struct. & Improv.	67,397,443	2,771,995	64,625,448	2.97%	1,919,376
342	Fuel Holders, Producers & Access.	14,994,662	192,026	14,802,636	2.41%	356,744
343	Prime Movers	578,025,418	77,232,826	500,792,592	3.99%	19,981,624
344	Generators	830,822,966	-	830,822,966	4.24%	35,226,894
345	Accessory Electric Equip.	112,165,889	5,481,438	106,684,451	3.16%	3,371,229
346	Misc. Power Plant Equip.	10,000,412	593,478	9,406,934	3.47%	326,421
347	ARO Cost - Other Prod.	43,620,335	-	43,620,335	4.41%	1,923,657
114	Acquisition Adj. - Redbud	148,301,899	-	148,301,899	3.70%	5,487,170
TOTAL OTHER PRODUCTION		1,806,514,135	87,456,874	1,719,057,261		68,593,115

1 The Proposed Annual Rates shown in the first seven lines are the same as proposed in Mr.
2 Spanos’s Depreciation Study.⁸ These proposed rates include recovery of the
3 Decommissioning Costs as estimated by Mr. Kopp.

4 The Account 347 line is an annual depreciation expense for Other Production AROs. As is
5 reasonable, ratepayers would be charged for both the AROs and separately for the
6 depreciation expenses resulting from Mr. Spanos’s proposed depreciation rates.

7 **Q. WHAT IS INCLUDED IN THE OTHER PRODUCTION AROS?**

8 A. The Other Production AROs consist entirely of the future costs to remove the three wind
9 farms. For example, the ARO is \$19,684,115.87 for the “Removal of Windfarm Structures”

depreciation rates, but does not eliminate the double recovery of the removal cost of the Wind Generating Facilities.

⁷ See OGE Application Package, Volume II, Schedule I-1-1 (Jan. 16, 2018).

⁸ Spanos Direct, Ex. JJS-2, at VI-4–VI-5.

1 at the Crossroads wind farm. This is shown in the OGE response to AG-OGE-21-2, which
2 is attached as Exhibit WWD-6.

3 **Q. WHAT IS INCLUDED IN THE DECOMMISSIONING COSTS MR. KOPP**
4 **PROVIDED FOR THE CROSSROADS WIND FARM?**

5 A. The decommissioning costs of the Crossroads Wind Farm Mr. Kopp presented include the
6 following:

7 Wind farm projects will be demolished to the *level legally required*.

8 Information on legal requirements has been provided by OGE. Demolition
9 is required to a depth of 30 inches below grade.⁹

10 **Q. COULD YOU COMPARE WHAT MR. KOPP INCLUDED IN THE**
11 **DECOMMISSIONING STUDY TO WHAT SHOULD BE INCLUDED IN THE**
12 **ARO?**

13 A. A removal that is “legally required,” as Mr. Kopp described, meets the definition of what
14 is to be included in an ARO. The Federal Energy Regulatory Commission (“FERC”)
15 Uniform System of Accounts General Instructions state the following:

16 An asset retirement obligation represents a liability for the legal obligation
17 associated with the retirement of a tangible long-lived asset that a company
18 is required to settle as a result of an existing or enacted law, statute,
19 ordinance, or written or oral contract or by legal construction of a contract
20 under the doctrine of promissory estoppel.¹⁰

⁹ Direct Test. of Jeffrey T. Kopp, Manager, Business Consulting for Burns and McDonnell, on behalf of Oklahoma Gas and Electric Co., Ex. JTK-1, at 4–6 (Jan. 16, 2018) [hereinafter “Kopp Direct”] (emphasis added).

¹⁰ 18 C.F.R. pt. 101(25)(A).

1 **Q. WHAT PROBLEM HAVE YOU IDENTIFIED?**

2 A. In spite of the fact that the future demolition of the wind farm is included in the ratepayers-
3 supported AROs, Mr. Kopp and Mr. Spanos also included the future demolition of the wind
4 farms in the decommissioning cost estimates that are included in Mr. Spanos’s calculation
5 of his proposed depreciation rates. OGE is proposing to double-recover the costs of
6 demolition of the wind farms.

7 **Q. HAVE YOU IDENTIFIED ANY OTHER PROBLEMS WITH OGE’S DOUBLE-
8 RECOVERY OF WIND FARM AND ASBESTOS REMOVAL COSTS?**

9 A. Yes. As demonstrated, the decommissioning costs Mr. Kopp provided to Mr. Spanos
10 included the double-recovery of asbestos and wind farm removal. However, Mr. Spanos
11 further increased the decommissioning costs Mr. Kopp provided to him. For example, the
12 Crossroads Wind Farm Decommissioning Cost Mr. Kopp provided to Mr. Spanos was
13 \$2,317,000, but Mr. Spanos “escalated” this amount to \$3,891,591.¹¹ Mr. Spanos further
14 increases costs that were already double recovered.
15 Mr. Spanos increased the decommissioning cost estimates provide to him by Mr. Kopp by
16 79 percent, on average. The decommissioning cost estimates provided to Mr. Spanos by
17 Mr. Kopp totaled \$154,219,900 for all production units.¹² Mr. Spanos increased this to
18 \$276,496,963.¹³ Mr. Spanos used the term “escalation” to describe his proposed increase
19 of the Decommissioning Cost Estimates.

¹¹ Spanos Direct, Ex. JJS-2, at VIII-4.

¹² Spanos Direct, Ex. JJS-2, at VIII-4 (showing initial amount in column 2).

¹³ Spanos Direct, Ex. JJS-2, at VIII-4 (showing increased amount in column 3).

1 Since Mr. Kopp and OGE were approximately double recovering the asbestos removal and
2 wind farm decommissioning costs, the fact that Mr. Spanos increased Mr. Kopp's estimates
3 by another 79 percent means they are proposing to nearly triple recovery of these costs.

4 **3. SPANOS ALTERATIONS OF "BOOK" DATA**

5 **Q. YOU PREVIOUSLY DISCUSSED THE FACT THAT IN THE RECENT PSO**
6 **PROCEEDING, THE COMMISSION FOUND THAT MR. SPANOS HAD**
7 **ALTERED DATA. HAS MR. SPANOS ALSO ALTERED DATA IN THE**
8 **CURRENT OGE PROCEEDING?**

9 A. Yes. In this proceeding, Mr. Spanos altered the numbers he claims are the "Book Salvage"
10 numbers. He altered the data in the direction that tends to result in higher depreciation rates.
11 For example, attached as Exhibit WWD-7 are the pages from Mr. Spanos's depreciation
12 study that show what he states are the "Book Salvage" amounts for Account 364, Poles,
13 Towers and Fixtures. Mr. Spanos labeled these pages "Summary of Book Salvage." Near
14 the middle of page VIII-44, he showed that the book net salvage is negative \$43,779,835
15 for the 26 years shown.

16 However, the alleged negative \$43,779,835 "book" net salvage is not the actual book net
17 salvage. The negative \$43,779,835 is *after* Mr. Spanos had altered the actual book data.
18 The actual book net salvage for that account for that time period is negative \$34,690,914.
19 The following Table 3 shows the actual book salvage of OGE, and Mr. Spanos's alteration
20 of the actual book salvage data:

Table 3¹⁴

Account 364, Poles, Towers and Fixtures				
(Years 1991 through 2016)				
	<u>Retirements</u>	<u>Cost of Removal</u>	<u>Gross Salvage</u>	<u>Net Salvage</u>
Book Salvage	67,746,072	64,566,292	29,875,378	(34,690,914)
Spanos Alteration	0	0	(9,088,921)	
Altered Salvage	67,746,072	64,566,292	20,786,457	(43,779,835)

1 Mr. Spanos removed over \$9 million of gross salvage from the actual gross salvage
 2 recorded in the Company records. What Mr. Spanos specifically called the “book salvage”
 3 on page VIII-44 of Exhibit JJS-2 is not the “book salvage.”

4 In his testimony, Mr. Spanos specifically refers to this “26-year period experienced
 5 \$43,779,835” negative net salvage and states this amount is one thing he specifically
 6 considered in arriving at his net salvage recommendation for this Account 364.¹⁵ Mr.
 7 Spanos’s altered negative \$43,779,835 “book” net salvage amount tends to result in higher
 8 depreciation rates than would be produced using the actual book net salvage amount of
 9 negative \$34,690,914, everything else being equal.

10 **Q. IN HIS DIRECT TESTIMONY OR DEPRECIATION STUDY DID MR. SPANOS**
 11 **DISCLOSE THAT HE HAD ALTERED WHAT HE PRESENTED AS THE**
 12 **“BOOK” OR “HISTORIC” OR “RECORDED” NET SALVAGE DATA?**

13 **A. No.** Nowhere in his direct testimony, depreciation study, the minimum filing requirements,
 14 or initial workpapers did Mr. Spanos disclose that he had altered what he claimed was the
 15 “book” or “historic” or “recorded” salvage data.

¹⁴ See OGE Response to AG-OGE-3-7, attached in Ex. WWD-8. Additionally, as part of Mr. Spanos’s reimbursement adjustments, no retirements were excluded from the life table in section VII of Mr. Spanos’s depreciation study. See OGE Response to AG-OGE-11-5; attached in Ex. WWD-8.

¹⁵ Spanos Direct 28:10–12.

1 For example, in his testimony Mr. Spanos stated that he “estimated the net salvage
2 percentages by incorporating the historical data for the period 1991 through 2016,” without
3 any mention of altering that “historical data.”¹⁶ In another place, Mr. Spanos stated that he
4 used “the net salvage analyses of historical plant retirement data recorded through 2016”
5 without mentioning any alteration to that “historical” “recorded” data.¹⁷

6 Similar to the recent PSO case, Mr. Spanos has again altered the data but did not reveal
7 that alteration in his direct testimony or depreciation study. Further, Mr. Spanos’s net
8 salvage data alterations are in the direction that tends to result in higher depreciation rates,
9 everything else equal.

10 **Q. CAN YOU DESCRIBE WHEN MR. SPANOS FIRST ADMITTED THAT HE HAD**
11 **ALTERED WHAT HE CLAIMED WAS THE “BOOK” OR “HISTORIC” OR**
12 **“RECORDED” NET SALVAGE DATA?**

13 A. Mr. Spanos did not reveal this alteration until the AG specifically asked Mr. Spanos if the
14 amounts he was presenting as the book salvage amounts were different than the amounts
15 “that were booked”. In AG-OGE-3-7, the Attorney General asked the following question:

16 (a) Were there any amounts that were booked and then excluded from the
17 Net Salvage Statistics data shown in Page VIII of the 2016 Depreciation
18 Study?

19 OGE provided the following response:

¹⁶ Spanos Direct 25:2–3. Mr. Spanos did state that he split the net salvage percentages for “generating facilities” into “interim” and “terminal net salvage,” *see* Spanos Direct 25:8–15, but this would not affect distribution or transmission plant accounts like Account 364, Poles, Towers and Fixtures.

¹⁷ Spanos Direct, Ex. JJS-2, at I-2. Mr. Spanos also referred to his use of historical data without disclosing his alterations in another location. *See* Spanos Direct, Ex. JJS-2, at IV-2.

1 (a) There were retirements and associated cost of removal and gross salvage
2 that were booked but excluded from the Net Salvage Statistics data shown
3 in Part VIII of the 2016 Depreciation Study.¹⁸

4 **Q. YOU STATED THAT MR. SPANOS HAD ALTERED GROSS SALVAGE DATA.**
5 **COULD YOU DESCRIBE WHAT GROSS SALVAGE MEANS?**

6 A. Yes. *Public Utilities Depreciation Practices*, published by the National Association of
7 Regulatory Utility Commissioners (“NARUC”) provides the following definition of “gross
8 salvage”:

9 **Gross Salvage**

10 The amount recorded for the property retired due to the sale,
11 *reimbursement*, or reuse of the property.¹⁹

12 In spite of the fact that reimbursement is clearly included in the definition of “gross
13 salvage,” Mr. Spanos removed the reimbursement amounts from his altered gross salvage
14 numbers.

15 **Q. WHAT GROSS SALVAGE DID MR. SPANOS REMOVE FROM ACCOUNT 364?**

16 A. Pertaining to the gross salvage recorded in the year 2015 that Mr. Spanos removed in his
17 analysis, the Company provided the following explanation:

18 Response: The \$1,229,974 gross salvage was a reimbursement in 2015 for
19 Account 364 related to a few highway relocations of distribution lines.
20 There was no identified cost of removal specific to these relocations. The

¹⁸ OGE Response to AG-OGE-3-7, attached in Ex. WWD-8.

¹⁹ NARUC, *Public Utilities Depreciation Practices* 320 (1996), excerpt attached as Ex. WWD-17 (emphasis added).

1 amount *was not excluded* from the Company *records*, however, it *was*
2 *excluded from the presentation in Part VIII* of John J. Spanos Direct
3 Exhibit JJS-2. The amount was recorded in Account 108, Accumulated
4 Provision for Depreciation.²⁰

5 This response shows that the Company records *did include* the reimbursement in the book
6 gross salvage. Including reimbursement in the gross salvage is correct and is consistent
7 with the definition of “gross salvage.” However, Mr. Spanos altered the booked data such
8 that the reimbursement was *excluded* from what Mr. Spanos presented as the “book
9 salvage” in Part VIII of his depreciation study.

10 **Q. PLEASE EXPLAIN THE “HIGHWAY RELOCATIONS” AS DISCUSSED IN THE**
11 **ABOVE COMPANY RESPONSE.**

12 A. OGE facilities, such as poles, might be in the way of a government construction project,
13 such as widening a road.²¹ The Fifth Amendment to the U.S. Constitution includes the
14 requirement that “nor shall private property be taken for public use, without just
15 compensation.” If the poles in the way of a government construction project are owned by
16 OGE on private property, the government agency cannot just take this OGE property
17 without paying OGE “just compensation,” on advice of counsel.²² OGE properly records
18 in its records the payments from the government to take the OGE property as “gross
19 salvage” received for the OGE property taken.²³ However, when presenting what he

²⁰ OGE Response to AG-OGE-11-12, attached in Ex. WWD-8 (emphasis added).

²¹ Poles are used as the example. There may also or instead be other facilities, such as conductors.

²² In a different circumstance, if OGE facilities were first constructed on what was then the government right-of-way, the government may be able to require the removal of those OGE facilities at OGE’s cost under certain circumstances. See OGE Response to AG-OGE-22-6(e), (f), attached in Ex. WWD-8.

²³ This is generally negotiated, although I am including a negotiated taking in the term “taken.”

1 portrays as the “book” or “experienced” net salvage,²⁴ Mr. Spanos alters that book data by
2 removing the reimbursement gross salvage.

3 **Q. WHAT EXPLANATION HAS MR. SPANOS PROVIDED FOR REMOVING THE**
4 **REIMBURSEMENT GROSS SALVAGE?**

5 A. Mr. Spanos stated the following:

6 This entry was a reimbursement that was not considered a normal or
7 recurring transaction, therefore, informed judgment in determining a future
8 net salvage estimate for all existing assets should not be focused on this
9 estimate.²⁵

10 **Q. ARE SUCH REIMBURSEMENTS RECURRING?**

11 A. Yes. In Account 364, OGE has received reimbursement gross salvage *every year* for which
12 we have detailed data, which are the years 1991 through 2016.²⁶ Something that occurs
13 every year is recurring. In addition, there is no valid reason to assume that there will be no
14 construction projects, or other activities, in the future that will result in reimbursement
15 gross salvage.²⁷

16 **Q. OTHER THAN GOVERNMENT-CAUSED RELOCATIONS, ARE THERE ANY**
17 **OTHER SOURCES OF REIMBURSEMENT GROSS SALVAGE?**

18 A. According to OGE’s response to AG-OGE-11-12, all of the reimbursement gross salvage
19 in Account 364 in 2015 that Mr. Spanos removed was “related to a few highway relocations

²⁴ See Spanos Direct 28:10–12.

²⁵ OGE Response to AG-OGE-11-2, attached in Ex. WWD-8.

²⁶ See OGE Response to AG-OGE-3-7, including its attachment.

²⁷ In addition, my calculations do not assume that reimbursement will be received “for all existing assets” (quote from OGE response to AG-OGE-11-2). It is reasonable to expect that in the future reimbursements will be received for *some* assets, similar to what has occurred in the past.

1 of distribution lines.” However, when a non-governmental entity is willing to pay OGE for
2 OGE utility facilities to be removed from an existing location and relocated, some or all of
3 those payments to OGE are also often considered reimbursement gross salvage.²⁸

4 **Q. YOU HAVE DISCUSSED MR. SPANOS’S ALTERATIONS TO GROSS SALVAGE**
5 **IN ACCOUNT 364. COULD YOU DESCRIBE ANY ALTERATIONS HE MADE**
6 **TO OTHER TRANSMISSION AND DISTRIBUTION ACCOUNTS?**

7 A. Yes. In his “reimbursement” adjustments, Mr. Spanos excluded \$31,174,933 from the
8 booked Gross Salvage amounts during the years 1991 through 2016 in total for accounts
9 355, 356, 364, 365, 366, 367, and 369.²⁹ Although he reduced the Gross Salvage amount
10 in his “reimbursement” adjustments by significant amounts, Mr. Spanos made only a
11 handful of relatively minor adjustments to the booked Retirement amounts and Cost of
12 Removal amounts for Accounts 355, 356, 364, 365, 366, 367, or 369.³⁰

13 **Q. WHAT DO YOU RECOMMEND IN RESPONSE TO MR. SPANOS’S**
14 **ALTERATIONS OF HISTORICAL DATA ON GROSS SALVAGE?**

15 A. As in the PSO case, this analysis again shows that we cannot trust the information presented
16 by Mr. Spanos. In his testimony, he said that the “experienced” net salvage for Account
17 364 was negative \$43,779,835.³¹ This negative \$43,779,835 is also shown on the

²⁸ In addition, in response to AG-OGE-13-6, OGE stated that “there are a few entries with the word ‘reimbursements’ in the comment column that reflect payments received by OG&E related to damaged or destroyed OG&E property.”

²⁹ See OGE Response to AG-OGE-3-7, including its attachment.

³⁰ See OGE Response to AG-OGE-3-7, including its attachment. The attachment “AG 3-7_Att” also shows adjustments *other* than “reimbursements” adjustments, including a sale. Mr. Spanos did adjust the Retirement amount a total of \$87, he did adjust the booked Cost of Removal by a total of \$960,825, and he did reduce the booked Gross Salvage by an additional \$1,696,924 in accounts 355, 356, 364, 365, 366, 367, or 369. In accounts 355, 356, 364, 365, 366, 367, or 369 I have not disagreed with, or made any adjustment to, this sale adjustment or to any net salvage adjustments *other* than “reimbursements” adjustments.

³¹ See Spanos Direct 28:10–12.

1 “Summary of Book Salvage” in his depreciation study.³² Yet the actual “book salvage” is
2 negative \$34,690,914 for this account for this time period. What Mr. Spanos claims is the
3 “book salvage” is *not* the “book salvage.” No weight should be given to Mr. Spanos’s
4 depreciation study. We cannot trust his numbers or testimony. We know what he claimed
5 to be the “book salvage” is not the book salvage. There is no way to know what other
6 information Mr. Spanos presents is also not actually what he claims it to be.

7 **Q. OTHER THAN GIVING NO WEIGHT TO MR. SPANOS’S DEPRECIATION**
8 **STUDY, WHAT ELSE DO YOU RECOMMEND REGARDING GROSS SALVAGE**
9 **HISTORICAL DATA?**

10 A. “Reimbursement” is specifically included in the definition of “gross salvage.”
11 Reimbursements occur every year and there is no valid reason to assume reimbursements
12 will not exist in the future.³³ As was done on the OGE books, I have included the
13 reimbursement gross salvage in the gross salvage. Mr. Spanos’s removal of the
14 reimbursement gross salvage tends to create depreciation rates higher than they otherwise
15 would be, everything else being equal. I have corrected this problem.

16 **Q. WHAT IS EXHIBIT WWD-8?**

17 A. Exhibit WWD-8 contains the responses from OGE to the Attorney General’s requests
18 pertaining to reimbursement, which have been discussed in this section.

³² See Spanos Direct, Ex. JJS-2, at VIII-44.

³³ The fact that the reimbursements were recorded on the books does not solve the problem. The recorded data on the books is correct, but we look at past experience to help in estimating future net salvage. By eliminating the reimbursement gross salvage, Mr. Spanos is effectively assuming the future reimbursement gross salvage will not exist. To help understand this, the past recorded Cost of Removal was recorded on the books and is also (properly) included in the net salvage data considered when estimating future net salvage. The past reimbursement gross salvage likewise was recorded on the books and also properly should be included in the net salvage data considered when estimating future net salvage.

1 4. **RELIABILITY OF SPANOS'S FORECASTS**

2 Q. **WHAT DOES MR. SPANOS STATE ABOUT THE ROLE OF "JUDGMENT" IN**
3 **HIS DEPRECIATION STUDY?**

4 A. Mr. Spanos states the following in his testimony:

5 Q. You used the term "judgment" in your explanation of how service lives
6 and net salvage are estimated. Why is judgment important for the estimation
7 of depreciation?

8 A. Depreciation is a process of forecasting the future, and the service life
9 and net salvage estimates represent expectations about what will happen
10 many decades from now.³⁴

11 Q. **SHOULD DEPRECIATION EXPENSE BE BASED UPON MR. SPANOS'S**
12 **"JUDGMENT" ABOUT "WHAT WILL HAPPEN MANY DECADES FROM**
13 **NOW"?**

14 A. No. The Commission should not set depreciation rates based on Mr. Spanos's forecasts
15 decades into the future. As I will now demonstrate, even Mr. Spanos's very short range
16 forecasts are highly inaccurate. Obviously, "forecasting" what will happen many decades
17 in the future is much more difficult than forecasting what is expected to occur in the very
18 near future.

19 Q. **PLEASE DESCRIBE SHORT-RANGE FORECASTS FROM MR. SPANOS THAT**
20 **HAVE PROVEN TO BE HIGHLY INACCURATE.**

21 A. In his testimony filed on December 18, 2015, in the prior OGE rate case, Mr. Spanos
22 provided his forecast of what the future retirement amounts would be in Account 373.0,

³⁴ Spanos Direct 20:24-27.

1 Street Lighting and Signal Systems.³⁵ The “2015” and “2016” columns of Table 4 below
 2 shows Mr. Spanos’s forecasts in that prior case of what the retirement amounts would be
 3 in the years 2015 and 2016. Table 4 also shows what we now know the actual retirements
 4 were in the years 2015 and 2016.

Table 4³⁶

Account 373, Street Lighting and Signal Systems			
	Spanos Forecasts in the Prior Case (Cause No. PUD 201500273)		Spanos Forecast This Case (Cause No. PUD 201700496)
	2015	2016	2017
Spanos Forecasted Retirements	\$11,000,000	\$11,000,000	\$9,950,000
Actual Retirements	\$1,502,671	\$1,289,829	\$865,262
Spanos Over-Estimate	\$9,497,329	\$9,710,171	\$9,084,738
Forecast/Actual Ratio	7 Times	9 Times	11.5 Times

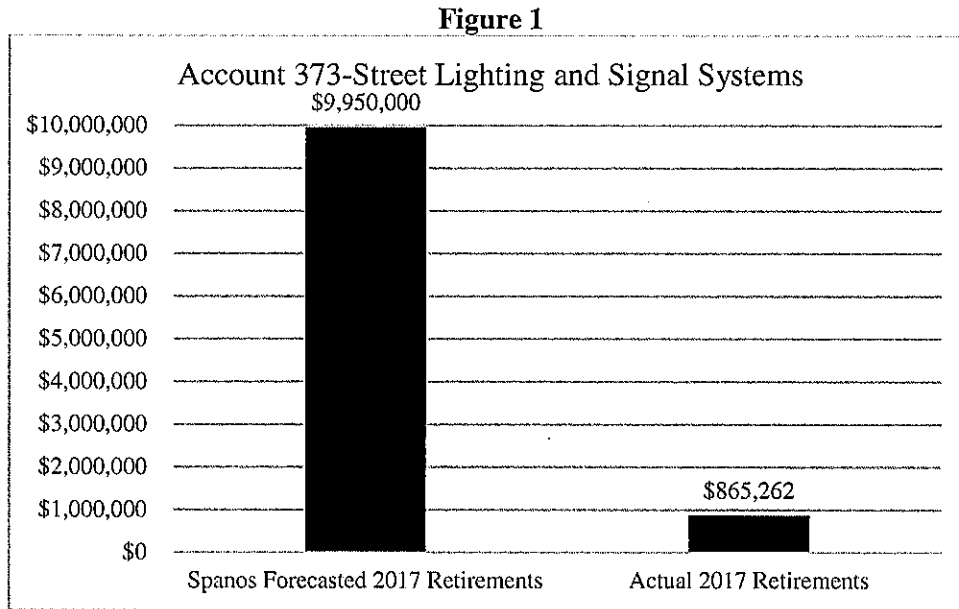
5 As can be seen from the “2015” and “2016” columns, Mr. Spanos’s forecasts of future
 6 retirements in the prior OGE proceeding were greatly overstated. His forecast retirement
 7 amounts were seven and nine *times* the retirement amounts that actually occurred.

8 The “2017” column of Table 4 above shows the forecast of retirements in the year 2017
 9 that Mr. Spanos used in this *current* OGE proceeding, Cause No. PUD 201700496. As can
 10 be seen from the “2017” column, Mr. Spanos’s forecast was that \$9,950,000 would retire
 11 in this Account 373 in the year 2017. The OGE FERC Form 1 is now available for the year

³⁵ Direct Test. of John J. Spanos on behalf of Oklahoma Gas and Electric Co. 10:12–20, *Okla. Gas & Elec. Co. Rates, Charges, and Tariffs for Retail Elec. Serv.*, No. PUD 201500273 (Dec. 18, 2015).

³⁶ See OGE Response to AG-OGE-13-15; OGE 2017 FERC Form 1, at 207; OGE Response to AG-OGE-1-3, Att. “OGE2016-Acct 373 Projected data.xlsx.”

1 2017. The actual retirements in 2017 were \$865,262 in Account 373. Mr. Spanos's forecast
2 of retirements in the year 2017 was over *11 times* the retirements that actually occurred.
3 The following chart is provided to help understand how inaccurate Mr. Spanos's forecast
4 in this case is:



5 **Q. WHAT IS ESPECIALLY TROUBLING ABOUT MR. SPANOS'S DRASTIC**
6 **OVER-ESTIMATE OF THE RETIREMENTS THAT WOULD OCCUR DURING**
7 **THE YEAR 2017?**

8 A. Mr. Spanos recently prepared the depreciation study and testimony he filed in this
9 proceeding,³⁷ so forecasting what the retirements would be in the year 2017 was a very
10 short-range forecast. But even for this very short-range forecast, his forecasted 2017
11 retirement amount was over 11 times the actual 2017 retirement amount. The fact that he
12 could not, or would not, provide anywhere near a reasonable forecast for this very short-

³⁷ Mr. Spanos included data through December 31, 2016, in his study. Complete data for year-end 2016 is not available until early 2017.

1 range estimate indicates that his forecasts of what will allegedly occur decades in the future
2 should be given little or no weight. Forecasting what will happen many decades in the
3 future is much more difficult than forecasting what is expected to occur in the very near
4 future.

5 Not only were his forecasts shown on Table 4 greatly in error, they were greatly in error in
6 the direction that produces higher depreciation rates, everything else being equal.³⁸

7 **Q. WHAT IS EXHIBIT WWD-9?**

8 A. Exhibit WWD-9 contains the pages from the OGE FERC Form 1s for the years 2015, 2016,
9 and 2017 that show the actual retirement amounts in Account 373 each of those years.
10 These are the amounts shown in the prior Table 4. We have circled each of these amounts.

11 **Q. WHAT IS EXHIBIT WWD-10?**

12 A. Exhibit WWD-10 are the source documents showing the Mr. Spanos's forecasted amounts
13 as shown in the prior Table 4.³⁹

14 **5. MISREPRESENTATION OF LED REPLACEMENT PROGRAM**

15 **Q. WERE THERE ANY OTHER PROBLEMS WITH MR. SPANOS'S FORECASTS**
16 **FOR ACCOUNT 373?**

17 A. Yes. Mr. Spanos testified in this proceeding that OGE "has planned a conversion to LED
18 lighting in Account 373, Street Lighting and Signal Systems."⁴⁰ However, OGE's plans to

³⁸ For example, the millions of dollars of additional investment that Mr. Spanos assumed would retire in 2017, but did not retire in 2017, have a longer life than he assumed. Longer life results in lower depreciation rates, everything else being equal.

³⁹ Mr. Spanos's response to AG-OGE-3-15 and AG-OGE-1-3 shows the amounts he expected would retire in 2015 separately for each install year. *See* Ex. WWD-10, at 2, 4, 5. I have added the total of these amounts.

⁴⁰ Spanos Direct 28:25–29:3.

1 use LED street lights were not as extensive as indicated by Mr. Spanos's retirement
2 forecast.

3 **Q. COULD YOU DESCRIBE OGE'S USE OF LED STREET LIGHTS IN 2017?**

4 A. Contrary to Mr. Spanos's forecast of massive retirements in 2017 to convert to LED street
5 lights, OGE was not engaged in retiring massive amounts of existing investments in order
6 to convert to LEDs during 2017. In a press release dated January 3, 2017, OGE stated the
7 following:

8 New OG&E streetlights in two northeast Oklahoma City corridors will give
9 the City and residents *two years to evaluate* the benefits of advanced light-
10 emitting diode (LED) technology on our streets.

11 . . .

12 The *two-year evaluation period* will let OG&E and the City test the lights'
13 year round durability in Oklahoma's weather, and evaluate the light'
14 effectiveness and cost of operation. *After two years*, the City has the option
15 to keep the lights or have them replaced with the standard pole and light
16 fixture and begin paying for operation costs."⁴¹

17 It should be noted that this press release from January 3, 2017, was released many months
18 prior to Mr. Spanos filing his testimony and depreciation studies on January 16, 2018.⁴²

19 Other documents also show that OGE's strategy is not to retire large addition amounts of
20 existing investment to convert to LEDs. As OGE representative Kathleen O'Shea stated in
21 an interview with Fox 25 news:

⁴¹ OGE Response to AG-OGE-15-5, Attachment 1, attached as Ex. WWD-11 (emphasis added).

⁴² Mr. Spanos included data through December 31, 2016, in his study. Complete data for year-end 2016 is not available until early 2017.

1 We're adopting an attrition strategy.

2 ...

3 Let's start replacing when the old ones hit end of service so it's a slower
4 process.⁴³

5 This OGE attrition strategy was confirmed in the request and the OGE response to AG-
6 OGE-15-6:

7 AG-OGE-15-6: Is it the policy of OGE to upgrade street lights to LED at a
8 time when the existing light requires service or replacement—for example,
9 when the light has ceased functioning or the bulb is burned out? If not, why
10 not?

11 Response: OG&E's policy will be to replace burned out bulbs with similar
12 bulbs if they are in stock. If a replacement bulb is not in stock or the actual
13 light fixture is failed or damaged, the fixture will be replaced with an LED
14 fixture. OG&E intends to deplete in-stock material first to minimize
15 stranded investment cost.⁴⁴

16 **Q. HOW MANY LED STREETLIGHTS DID OGE HAVE IN SERVICE BY THE END**
17 **OF 2017?**

18 A. By the end of 2017, OGE had 99 LED streetlights in service. To place this number in
19 context, OGE stated the following in a response to a discovery request regarding the end
20 of 2017:

⁴³ OGE Response to AG-OGE-15-4, attached as Ex. WWD-12.

⁴⁴ OGE Response to AG-OGE-15-6, attached as Ex. WWD-13.

1 Response: OG&E has 99 LED lights installed at three pilot sites, and a total
2 of approximately 250,000 street lights on its system. This is approximately
3 0.04%.⁴⁵

4 **Q. HOW MUCH EXISTING INVESTMENT DID OGE RETIRE IN ORDER TO**
5 **INSTALL THESE 99 LED STREETLIGHTS?**

6 A. Little or none. The OGE discovery responses state that all 99 of these LED streetlights
7 were new installation where there was no previously existing streetlight.⁴⁶

8 **Q. WHAT IS YOUR OVERALL EVALUATION OF MR. SPANOS'S STATEMENTS**
9 **ABOUT THE LED REPLACEMENT PROGRAM?**

10 A. It is clear that the OGE conversion to LEDs is much different than portrayed by Mr.
11 Spanos's large retirement forecasts.

12 **Q. DO YOU HAVE ANY OTHER COMMENTS ON STREET LIGHT**
13 **REPLACEMENT?**

14 A. The poles, support arms, and certain other investments in Account 373 do not have to be
15 retired if a street light is converted to LED. The *majority* of the investment in Account 373
16 is in facilities that would not need to be retired even if the existing street lights are
17 converted to LED.⁴⁷

⁴⁵ OGE Response to AG-OGE-15-7, attached as Ex. WWD-14.

⁴⁶ OGE Response to AG-OGE-14-10, attached as Ex. WWD-15.

⁴⁷ I calculated this outcome using investment amounts provided in discovery. See OGE Response to AG-OGE-14-12, attached in Ex. WWD-16; OGE Response to AG-OGE-14-13, attached in Ex. WWD-16. In his testimony, Mr. Spanos did state that "not all assets within the account will be replaced." Spanos Direct 28:28. However, he did not disclose that the *majority* of the investment will not be replaced.

1 **Q. DOES THE ABOVE INFORMATION HAVE SIGNIFICANCE BEYOND JUST**
2 **ACCOUNT 373, STREET LIGHTING AND SIGNAL SYSTEMS?**

3 A. Yes. This information again demonstrates that Mr. Spanos's presentations and forecasts
4 cannot be trusted.

5 **6. VIOLATION OF DEPRECIATION STUDY STANDARDS**

6 **Q. WHAT IS ONE STEP THAT IS REQUIRED IN A PROPER DEPRECIATION**
7 **STUDY?**

8 A. One of the major steps in a proper depreciation study is to accumulate and study the *past*
9 actual data of the company in a historical life analysis. NARUC's *Public Utility*
10 *Depreciation Practices* states the following:

11 Knowing what happened yesterday may help one to better understand what
12 is happening today and what may happen tomorrow. This is also true with
13 depreciation studies. Historical life analysis is *the study of past occurrences*
14 that may be used to indicate the future survivor characteristics of property.⁴⁸

15 **Q. HAS MR. SPANOS CONFORMED TO THIS STANDARD?**

16 A. He has not, specifically with respect to Account 373.0, Street Lighting and Signal Systems.

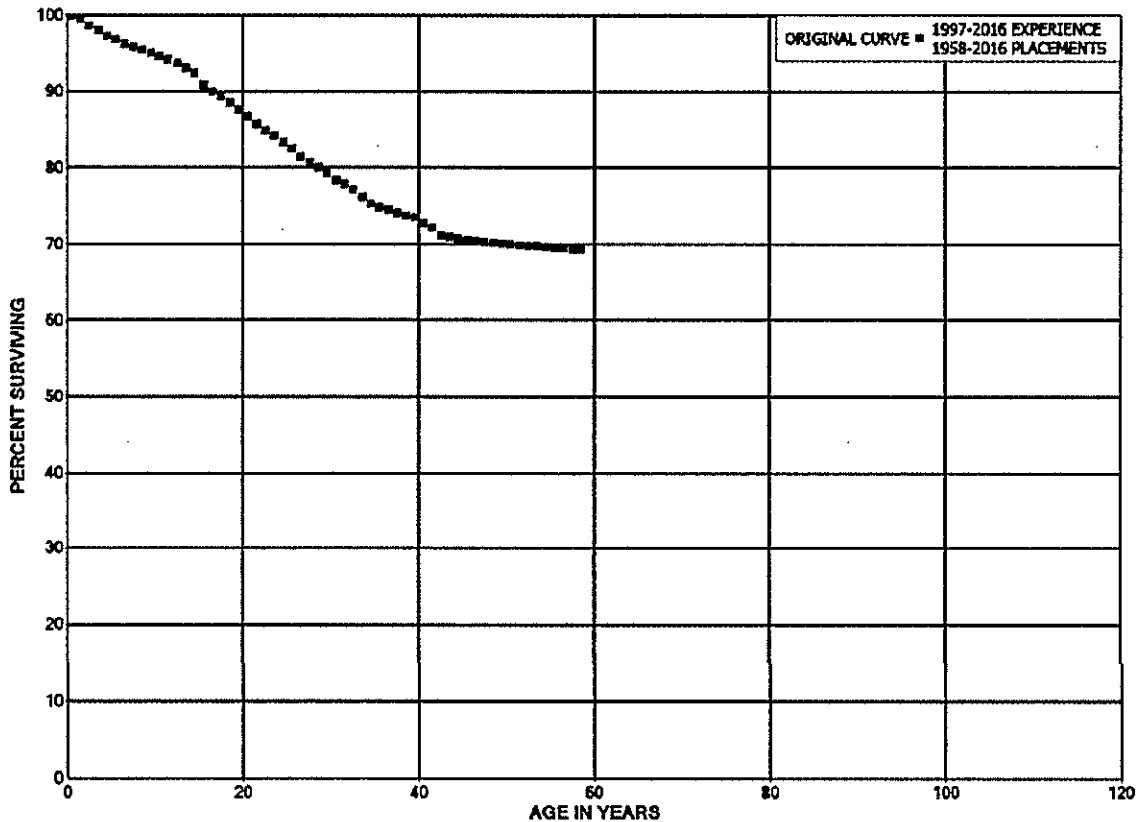
⁴⁸ NARUC, Public Utility Depreciation Practices 111 (1996), excerpt attached as Ex. WWD-17 (emphasis added).

1 Q. PLEASE PROVIDE THE HISTORICAL LIFE ANALYSIS SHOWING THE
2 ACTUAL OGE PAST EXPERIENCED DATA FOR ACCOUNT 373.0, STREET
3 LIGHTING AND SIGNAL SYSTEMS.

4 A. Shown below is the original Survivor Curve showing the actual OGE experienced data “of
5 past occurrences” for Account 373.0. This was provided by OGE in response to discovery
6 request AG-OGE-14-5, attached as Exhibit WWD-18.

Figure 2

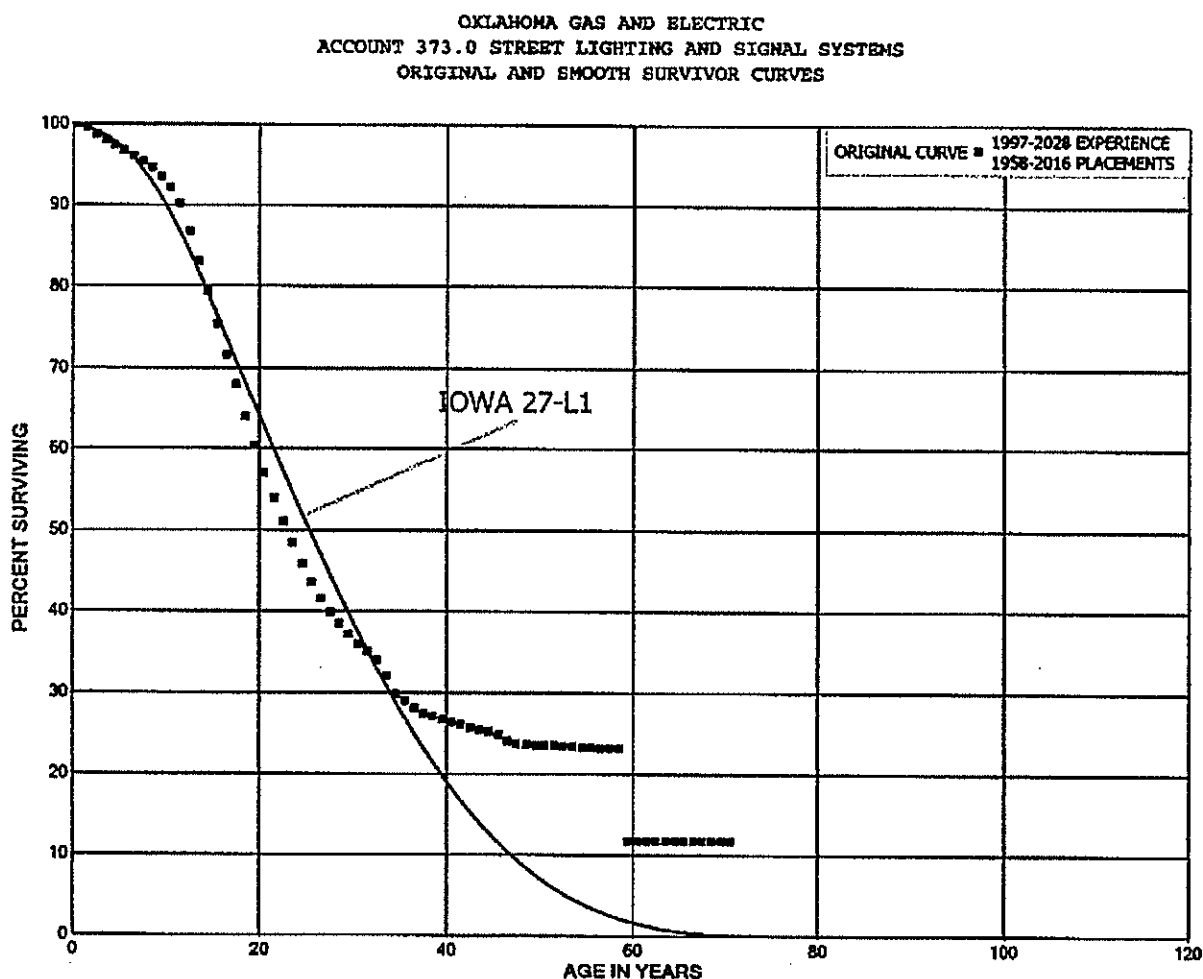
OKLAHOMA GAS AND ELECTRIC COMPANY
ACCOUNT 373.0 STREET LIGHTING AND SIGNAL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



7 Q. WHAT “EXPERIENCE” DATA DID MR. SPANOS FILE IN HIS DEPRECIATION
8 STUDY FOR ACCOUNT 373.0?

9 A. Figure 3 below shows the “experience” data Mr. Spanos provided for Account 373.0.

Figure 3⁴⁹



1 As is obvious from comparing these two figures, the “experience” data Mr. Spanos filed is
2 nowhere near the actual OGE experience data.

3 **Q. WHAT DID MR. SPANOS INCLUDE IN WHAT HE LABELED THE**
4 **“EXPERIENCE” DATA FOR THIS ACCOUNT?**

5 **A.** As can be seen in the upper right corner of Figure 3 above, the “Experience” data Mr.
6 Spanos used is for the years from 1997 to 2028.

⁴⁹ Spanos Direct, Ex. JJS-2, at VII-108.

1 On pages 28 and 29 of his direct testimony Mr. Spanos states:

2 The life analyses for Account 373, Street Lighting and Signal Systems, set
3 forth on pages VII-109 and VII-110 of Direct Exhibit JJS-2 includes the
4 historical analyses from 1997 through 2016 *as well as the projected*
5 *analyses for 2017 through 2028.*⁵⁰

6 Since 2028 is several years in the future, the historical life analysis Mr. Spanos presented
7 is not just “the study of past occurrences” as required in a proper depreciation study.

8 In his so-called “experience” data, Mr. Spanos added his forecasts for the years 2017-2028
9 to the actual OGE experience data for the years 1997 through 2016. The forecasts that he
10 added include his greatly over-stated retirement estimate of \$9,950,000 retirements in the
11 year 2017, which was previously discussed in this testimony.

12 **Q. IS IT ACCEPTABLE FOR AN ANALYST TO INCLUDE THAT ANALYST’S**
13 **FORECASTS OF THE FUTURE IN WHAT HE PRESENTS AS SO-CALLED**
14 **“EXPERIENCE” DATA?**

15 **A.** No. This violates accepted depreciation study requirements. The proper life analysis
16 contains two major *separate* steps, as stated in NARUC’s *Public Utility Depreciation*
17 *Practices*. The *first* major step is to study the *past* actual data of the Company for an
18 account:

19 Knowing what happened yesterday may help one to better understand what
20 is happening today and what may happen tomorrow. This is also true with

⁵⁰ Spanos Direct 28:28–29:1 (emphasis added).

1 depreciation studies. Historical life analysis is *the study of past occurrences*

2 that may be used to indicate the future survivor characteristics of property.⁵¹

3 *After* having studied the past data, the *second* major step is for the analyst to judge whether
4 this historical data reasonably depicts the expected future life of the property:

5 Actuarial analysis objectively measures how the company has retired its
6 investment. The analyst must *then* judge whether this historical view
7 depicts the future life of the property in service. The analyst takes into
8 consideration various factors, such as changes in technology, services
9 provided, or capital budgets.⁵²

10 As is clear from the above statements from *Depreciation Practices*, the historical life
11 analysis should include only “past occurrences.” Historical life analysis therefore does not
12 properly include an analyst’s projection of the future. As part of the later second step,
13 analysts are allowed and expected to judge whether future events will differ from the past
14 occurrences, but those judgment adjustments are not properly part of the historical life
15 analysis.

16 **Q. WHAT IMPORTANT INFORMATION IS LOST IF THE PRACTICE OF**
17 **INCLUDING AN ANALYST’S JUDGMENTAL ADJUSTMENTS IN THE**
18 **HISTORIC LIFE ANALYSIS IS ACCEPTED?**

19 A. The historical analysis of the past actual data is effectively a “reality check.” It indicates
20 how long the investments in the account actually live, based upon actual experience. When
21 Mr. Spanos includes his judgmental forecasts in the historic life analysis, that eliminates

⁵¹ NARUC, Public Utility Depreciation Practices 111 (1996), excerpt attached as Ex. WWD-17 (emphasis added).

⁵² *Id.* (emphasis added).

1 the reality check. By mixing his forecasts in with the actual historic data, he eliminates the
2 ability to distinguish what portion of his life proposal is based upon his judgment. He
3 eliminates the ability to compare his recommended life to the life of investments in the
4 account as indicated by actual experience.

5 If each analyst was allowed to adjust the historical experience data to include that analyst's
6 judgmental forecasts, each party could file their own judgmental version of the alleged
7 historic experience data. This would eliminate the ability to compare the parties' proposals
8 to the life as indicated by actual experience.

9 **Q. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?**

10 A. Mr. Spanos's failure to follow the accepted depreciation study practices should be rejected.
11 I have followed the existing practice consistent with the requirements in the *Depreciation*
12 *Practices*. The historical life analysis I present is the actual OGE experience data. I have
13 not adjusted this historical life data.

14 **Q. OVERALL, WHAT IS YOUR RECOMMENDATION PERTAINING TO THE**
15 **CREDIBILITY OF THE OGE DEPRECIATION STUDY?**

16 A. The Commission should give little or no weight to the OGE depreciation study, or, just as
17 the Commission did with Mr. Spanos's depreciation study in the recent PSO proceeding,
18 "reject" the study. As demonstrated above:

- 19 (1) OGE is proposing to double-recover the costs of removing asbestos;
20 (2) OGE is proposing to double-recover the costs of removing the wind farms;
21 (3) Mr. Spanos's escalation results in even greater increases to already double-
22 recovered amounts;

1 (4) In numerous accounts, Mr. Spanos altered what he said was the “book” and
2 “historic” and “recorded” data, without disclosing his alterations in his testimony,
3 depreciation study, or initial workpapers. Mr. Spanos’s alterations to the data were
4 in the direction which tends to increase depreciation rates, everything else equal;

5 (5) A depreciation study involves forecasting decades into the future. Even Mr.
6 Spanos’s short term forecasts are very inaccurate. The amount that Mr. Spanos
7 recently forecasted would retire in 2017 was over 11 times the actual 2017
8 retirement amount in Account 373;

9 (6) Mr. Spanos violated accepted depreciation practices and requirements by mixing
10 forecasts with past historical data. What is supposed to be the “study of past
11 occurrences” actually includes Mr. Spanos’s own forecasts.

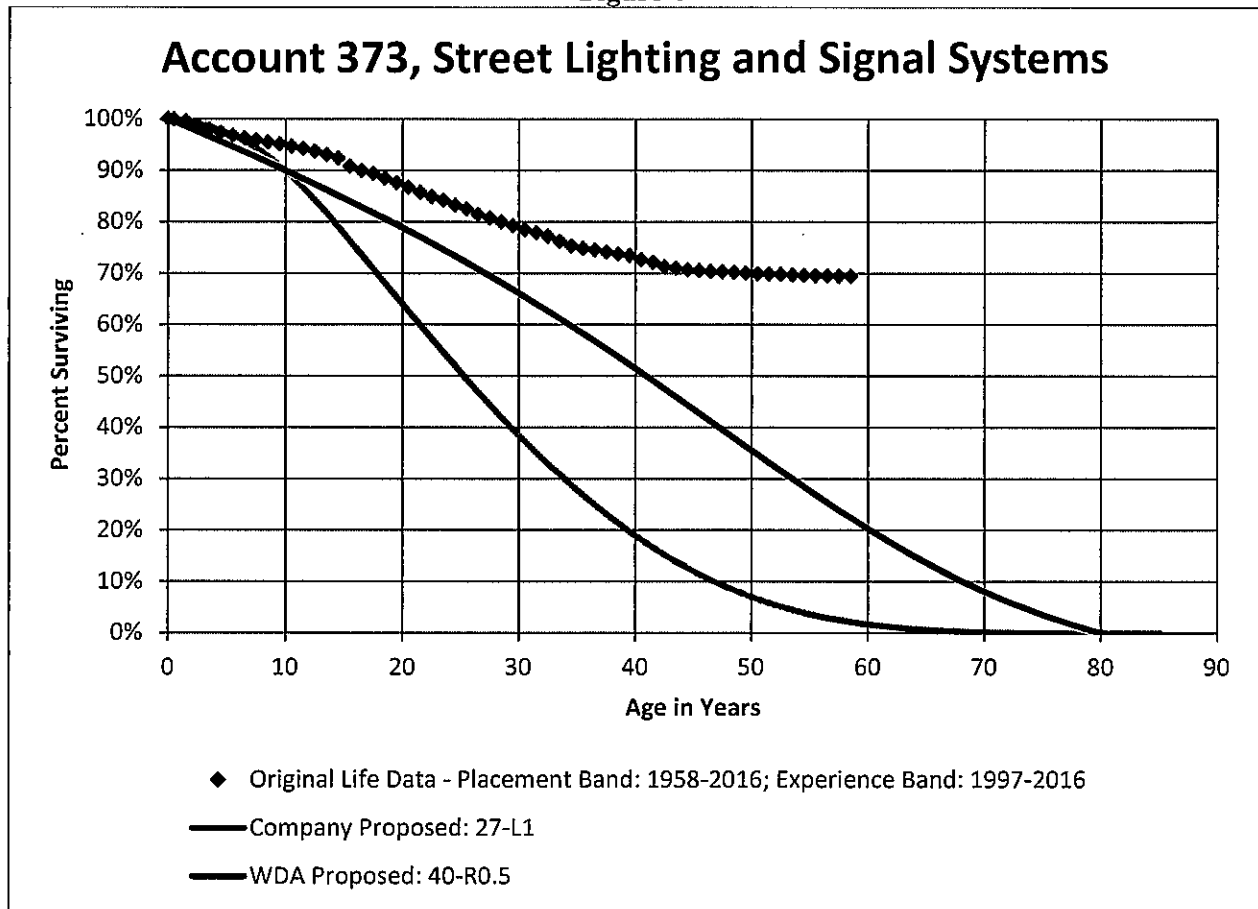
12 Depreciation expenses that will cost OGE’s customers hundreds of millions of dollars a
13 year should not be based on Mr. Spanos’s depreciation study for the reasons discussed
14 above. It does not have credibility.

III. AVERAGE SERVICE LIFE RECOMMENDATIONS

16 **Q. WHAT DO YOU RECOMMEND PERTAINING TO THE LIFE FOR ACCOUNT**
17 **373, STREET LIGHTING AND SIGNAL SYSTEMS?**

18 **A. I recommend a 40 year Average Service Life with a R0.5 dispersion (Iowa curve).**

Figure 4



1 As can be seen, my recommendation is a shorter Average Service Life than indicated by
2 the historic experience. I am recognizing that the Company may be converting to LEDs
3 from prior technologies, and the transition may result in a reasonable amount of accelerated
4 retirements. Of course, I have not gone to as short an Average Service Life as Mr. Spanos
5 recommends, since, as previously demonstrated, Mr. Spanos's forecasted annual
6 retirements are provably exaggerated.⁵³

⁵³ This means the average service life is longer than Mr. Spanos proposed, everything else being equal. For example, the millions of dollars of extra investment that Mr. Spanos assumed would retire in 2017, but did not retire in 2017, actually have a longer life than he assumed.

1 Q. SIMILAR TO FIGURE 4 SHOWN ABOVE, HAVE YOU PREPARED A
2 COMPARISON OF THE OGE ACTUAL EXPERIENCE “SURVIVOR” DATA
3 AND THE PROPOSED “SURVIVOR” CURVES FOR EACH ACCOUNT FOR
4 WHICH YOUR SERVICE LIFE RECOMMENDATION DIFFERS FROM MR.
5 SPANOS’S LIFE RECOMMENDATION?

6 A. Yes. This information is shown in Exhibit WWD-19. Table 5 below compares the
7 recommended Average Service Lives and Iowa Curves for all accounts for which the OGE
8 and AG recommendations differ.

Table 5⁵⁴

LIFE RECOMMENDATION COMPARISON			
Other Production Plant (Other Than Wind and Solar) - Interim Retirement Curve		OGE	AG
341.00	Structures & Impro.	45-R4	55-R4
343.00	Prime Movers	35-R2	50-R3
Distribution Plant			
366.00	Underground Conduit	60-R2	65-R2
370.00	Meters – Smart Meters	15-S2.5	19-R3
373.00	Street Lighting & Signal Sy.	27-L1	40-R0.5

9 Q. PLEASE FURTHER EXPLAIN YOUR LIFE ANALYSIS.

10 A. The historic data indicates how long the investments in an account live, as shown by actual
11 experience. The three possibilities for the future average service life of an account are (1)
12 the investments might live *longer* than indicated by actual experience because of changes
13 affecting the future as compared to the past; (2) the investments might have about the *same*
14 life in the future as indicated by actual past experience; or (3) investments might have a

⁵⁴ The table does not address differences in the expected final retirement dates for production units. Final retirement dates for production units are addressed in a later section of this testimony.

1 *shorter* life in the future than indicated by actual past experience due to changes affecting
2 the future as compared to the past. Absent convincing evidence that changes are occurring
3 that will significantly lengthen or significantly shorten asset lives, the “mid-range” of these
4 three possibilities is that, in the future, the investments might have about the same life as
5 indicated by actual experience.

6 **Q. COULD YOU PLEASE PROVIDE THE DEFINITION OF DEPRECIATION?**

7 A. Yes. FERC provides the following definition of depreciation in the FERC Uniform System
8 of Accounts:

9 Depreciation, as applied to depreciable electric plant, means the loss in
10 service value not restored by current maintenance, incurred in connection
11 with the consumption or prospective retirement of electric plant in the
12 course of service *from causes which are known to be in current operation*
13 *and against which the utility is not protected by insurance.* Among the
14 causes to be given consideration are wear and tear, decay, action of the
15 elements, inadequacy, obsolescence, changes in the art, changes in demand
16 and requirements of public authorities.⁵⁵

17 This definition, particularly the emphasized portion, shows that an analyst should not
18 speculate as to what new causes impacting depreciation might occur in the future. If a cause
19 is not “known to be in current operation” it is not properly included in the depreciation
20 analysis. In evaluating each account, if there is a cause “known to be in current operation”
21 that is reasonably expected to result in the future average service life being either

⁵⁵ 18 C.F.R. pt. 101(12) (emphasis added).

1 significantly longer or significantly shorter than indicated by the actual experience, I
2 considered that in my recommendation for that account.

3 **IV. PROBABLE RETIREMENT YEARS OF PRODUCTION UNITS**

4 **Q. FOR SOME PRODUCTION UNITS DOES MR. SPANOS USE A PROBABLE**
5 **RETIREMENT YEAR THAT IS EARLIER THAN THE RETIREMENT YEAR**
6 **SHOWN IN THE MOST RECENT INTEGRATED RESOURCE PLAN (IRP)?**

7 **A.** Yes. The IRP of OGE is attached to the testimony of Leon Howell.⁵⁶ Mr. Howell stated the
8 following in his testimony:

9 The retirement date for all of OG&E's Mustang units were assumed to be
10 by the end of 2017 and retirement dates for other gas steam generation units
11 are reflected in Figure 5 in the attached Direct Exhibit LCH-1.⁵⁷

12 That Figure 5, from page 29 of the IRP, is reproduced below:

Figure 5: Assumed Gas-Fired Steam Unit Retirements

Horseshoe Lake Plant	Seminole Plant
Unit 6 (169 MW) – 2024	Unit 1 (486 MW) – 2037
Unit 7 (209 MW) – 2029	Unit 2 (482 MW) – 2039
Unit 8 (394 MW) – 2035	Unit 3 (489 MW) – 2041

⁵⁶ See generally Direct Test. of Leon Howell on behalf of Oklahoma Gas and Electric Co., Ex. LCH-1 (Jan. 16, 2018) [hereinafter "Howell Direct"].
⁵⁷ Howell Direct 5:1–4.

1 **Q. FOR THESE PRODUCTION UNITS, PLEASE COMPARE THE PROBABLE**
 2 **RETIREMENT YEAR THAT MR. SPANOS USED TO THE RETIREMENT YEAR**
 3 **SHOWN IN THE IRP.**

4 **A.** See Table 6 below, which contains the relevant comparison.

Table 6

Gas-Fired Steam Production Units			
	IRP Assumed Retirement Year ⁵⁸	Spanos Probable Retirement Year ⁵⁹	Difference (Years)
Horseshoe Lake Plant			
Unit 6	2024	2023	-1
Unit 7	2029	2028	-1
Unit 8	2035	2029	-6
Seminole Plant			
Unit 1	2037	2030	-7
Unit 2	2039	2030	-9
Unit 3	2041	2030	-11

5 **Q. WHAT IMPACT DOES USING AN EARLIER RETIREMENT YEAR HAVE ON**
 6 **DEPRECIATION RATES?**

7 **A.** Using an earlier retirement year in the depreciation study produces higher depreciation
 8 rates, everything else being equal.

9 **Q. FOR ANY PRODUCTION UNIT, DID MR. SPANOS USE A PROBABLE**
 10 **RETIREMENT YEAR THAT WAS LATER THAN THE ASSUMED**
 11 **RETIREMENT YEAR SHOWN IN THE IRP?**

12 **A.** No.

⁵⁸ Howell Direct, Ex. LCH-1, at 29.

⁵⁹ Spanos Direct, Ex. JJS-2, at III-7.

1 Q. ARE ANY OF THE PRODUCTION UNITS SHOWN ON THE ABOVE TABLE 6
2 COAL-FIRED UNITS?

3 A. No. All of the units on Table 6 are fired by natural gas.

4 Q. WHAT PROBABLE RETIREMENT YEAR DID YOU USE IN YOUR
5 CALCULATIONS FOR THE PRODUCTION UNITS?

6 A. I used the probable retirement year shown in the OGE IRP for each production unit. If a
7 specific retirement year was not shown in the IRP for a unit, I accepted the probable
8 retirement year used by Mr. Spanos for that unit. I recommend the probable retirement
9 years used in my calculations be adopted.

10 **V. CORRECTION OF MR. SPANOS'S HIGH INFLATION ASSUMPTIONS**

11 Q. ADDRESSING ACCOUNT 364, POLES, TOWERS AND FIXTURES, OTHER
12 THAN THE PREVIOUSLY DISCUSSED FACT THAT \$43,779,835 IS NOT THE
13 ACTUAL BOOKED NEGATIVE NET SALVAGE, WHAT OTHER PROBLEM
14 EXISTS IN THIS NET SALVAGE ANALYSIS OF MR. SPANOS?

15 A. The net salvage analysis of Mr. Spanos also assumes that future inflation will include
16 inflation in excess of 10 per year.

17 Q. COULD YOU EXPLAIN HOW MR. SPANOS'S METHOD IS IMPACTED BY
18 PAST INFLATION RATES, SUCH AS INFLATION RATES HIGHER THAN 10
19 PERCENT?

20 A. Yes. Wolf and Fitch's *Depreciation Systems*, an important text on depreciation, stated the
21 following:

1 Salvage ratios are a function of inflation.⁶⁰

2 For example, in calculating his historic net salvage ratios for the year 2015, Mr. Spanos
3 divided the net salvage dollar amount incurred in the year 2015 (which net salvage is stated
4 in year-2015 dollars) by the original cost of the investment that retired during the year
5 2015. For example, if an investment that retired in the year 2015 was installed in 1965, the
6 original cost in the denominator is in year-1965 dollars.

7 The calculation of the historic net salvage ratio includes the impact of all inflation that
8 occurred between the time the investment was installed and the time it retired, since the net
9 salvage amount in the numerator is in *current* dollars but the original costs of the
10 investments in the denominator, are in historic original cost dollars, which may be in
11 dollars from decades earlier. In sum, due to inflation, the amounts in the numerator and
12 denominator of the net salvage ratio are in different price levels.

13 *Depreciation Systems* points out that using a net salvage ratio that includes current dollars
14 in the numerator and historic original cost dollars in the denominator is a ratio using
15 different units, stating the following:

16 One inherent characteristic of the salvage ratio is that the numerator and
17 denominator are measured in different units; the numerator is measured in
18 dollars at the time of retirement, while the denominator is measured in
19 dollars at the time of installation. Inflation is an economic fact of life and
20 although both numerator and denominator are measured in dollars, the
21 timing of the cash flows reflects different price levels.⁶¹

⁶⁰ Frank K Wolf & W. Chester Fitch, *Depreciation Systems* 267 (1994), attached in excerpt form as Ex. WWD-20 [hereinafter "*Depreciation Systems*"].

⁶¹ *Depreciation Systems* 53, attached in excerpt form as Ex. WWD-20.

1 **Q. PLEASE EXPLAIN WHAT YOU MEAN BY HIGH HISTORICAL INFLATION IN**
2 **MR. SPANOS'S HISTORIC NET SALVAGE ANALYSES.**

3 A. The high historic inflation levels in the past are incorporated into the historic net salvage
4 ratios Mr. Spanos shows in section VIII of his depreciation study. For example, from the
5 mid-1970s to the early-1980s, inflation was very high. According to the Consumer Price
6 Index ("CPI") published by the U.S. Bureau of Labor Statistics, the annual inflation rate in
7 1979 was 11.3%; in 1980 it was 13.5%; and in 1981 it was 10.3%.⁶²

8 **Q. IN PREPARING HIS FUTURE NET SALVAGE RECOMMENDATION, DID MR.**
9 **SPANOS ADJUST FOR THE POSSIBILITY THAT FUTURE INFLATION MAY**
10 **BE LOWER THAN PAST INFLATION HAD BEEN?**

11 A. Absolutely not. In AG-OGE-9-6, after referring to the CPI, the Attorney General asked the
12 following question:

13 In preparing the past net salvage data that is shown on page VIII-41 through
14 page VIII-60 of Direct Exhibit JJS-2, or in preparing Mr. Spanos's Future
15 Net Salvage factor recommendations for Distribution and Transmission
16 accounts, did Mr. Spanos adjust for the possibility that annual inflation in
17 the future might be less than annual inflation had been in the past?

18 The OGE response included:

19 Mr. Spanos did *not adjust* for the possibility that annual inflation may be
20 different in the future from the past.⁶³

⁶² Consumer Price Index – December 2017, Table 24, U.S. Bureau of Labor Statistics (Jan. 12, 2018), attached as Ex. WWD-21.

⁶³ OGE Response to AG-OGE-9-6, attached as Ex. WWD-22 (emphasis added).

1 Mr. Spanos’s use of the historic net salvage analyses, which includes these high historical
2 inflation rates, without adjusting for the “the possibility that annual inflation may be
3 different in the future from the past” means his proposed future net salvage
4 recommendations assumes that the same high inflation rates will continue in the future.
5 This is not a reasonable assumption, as will be discussed. It is also an assumption that
6 increases the negative net salvage, resulting in higher depreciation rates, all else being
7 equal.

8 **Q. WHAT IS A REASONABLE ESTIMATE OF INFLATION TO USE IN**
9 **STATISTICAL ANALYSES OF NET SALVAGE?**

10 A. A reasonable estimate of inflation is 2 percent, which is significantly lower than the
11 inflation included in the historical net salvage analysis included in the Company’s
12 depreciation proposal.

13 The Federal Open Market Committee (“FOMC”), which is a key entity of the Federal
14 Reserve System, is mandated by the U.S. Congress to promote “maximum employment,
15 stable prices, and moderate long-term interest rates.”⁶⁴ FOMC has determined that setting
16 monetary policies to achieve a 2 percent inflation rate fulfills its goals. FOMC has stated
17 the following about this goal:

18 The inflation rate over the longer run is primarily determined by monetary
19 policy, and hence the Committee has the ability to specify a longer-run goal
20 for inflation. The Committee reaffirms its judgment that inflation at the rate
21 of 2 percent, as measured by the annual change in the price index for

⁶⁴ Federal Open Market Committee, *Statement of Longer-Run Goals and Monetary Policy Strategy* (Jan. 30, 2018), attached as Ex. WWD-23.

1 personal consumption expenditures, is most consistent over the longer run
2 with the Federal Reserve's statutory mandate.⁶⁵

3 In addition, the CPI inflation rate has averaged 2.06% per year for at least the last 20
4 years.⁶⁶

5 **Q. DOES DEPRECIATION SYSTEMS PROVIDE AN ANALYTICAL METHOD FOR**
6 **USING A MORE REASONABLE LEVEL OF INFLATION TO ESTIMATE THE**
7 **FUTURE NET SALVAGE?**

8 A. Yes. *Depreciation Systems* discusses a method that first converts "the observed dollars to
9 constant dollars,"⁶⁷ which removes the high historic inflation rates, and then uses a more
10 reasonable estimate of the inflation.⁶⁸

11 *Depreciation Systems* first converts the historic salvage ratio to constant dollars by using
12 the CPI⁶⁹ to deflate the actual net salvage amounts to the year the related retired plant was
13 first installed. The deflation of the net salvage amounts results in a salvage ratio in which
14 both the numerator and denominator are "measured in dollars of the same price level."⁷⁰

15 Once the salvage amounts are stated at the same price level of the retired plant, and the
16 impact of the high historic inflation levels has therefore been removed, the next step is to
17 use a more reasonable estimate of inflation to aid in forecasting the future net salvage
18 ratios.⁷¹

⁶⁵ *Id.*

⁶⁶ The average inflation rate from 1998 to 2017 is 2.06%, calculated using CPI statistics included in Exhibit WWD-21.

⁶⁷ See *Depreciation Systems* 61, 263, attached in excerpt form as Ex. WWD-20.

⁶⁸ See *id.* at 265.

⁶⁹ See *id.* at 61.

⁷⁰ See *id.* at 263-64.

⁷¹ *Id.* at 265.

1 **Q. HAVE YOU PERFORMED THE ANALYSIS DISCUSSED IN *DEPRECIATION***
2 ***SYSTEMS* FOR THOSE ACCOUNTS IN WHICH YOUR FUTURE NET**
3 **SALVAGE RECOMMENDATION DIFFERS FROM MR. SPANOS'S FUTURE**
4 **NET SALVAGE RECOMMENDATION?**

5 A. Yes. In this analysis I used 2 percent as the annual inflation rate. The past net salvage ratio
6 information, adjusted to include a 2 percent annual inflation rate, is shown on my Exhibit
7 WWD-24.

8 **Q. PLEASE DISCUSS YOUR ESTIMATED FUTURE NET SALVAGE FOR**
9 **ACCOUNT 364, POLES, TOWERS, AND FIXTURES.**

10 A. Before I explain my estimate, it might be helpful to recall how Mr. Spanos described his
11 analysis:

12 The net salvage percent is presented on pages VIII-44 and VIII-45. The
13 percentage is based on the result of annual gross salvage minus the cost to
14 remove plant assets as compared to the original cost of plant retired during
15 the period 1991 through 2016. The 26-year period experienced \$43,779,835
16 (\$20,786,457-\$64,566,292) in net salvage for \$67,746,072 plant retired.
17 The result is negative net salvage of 65 percent ($\$43,779,835/\$67,746,072$);
18 however, the most recent five-year average is 91 percent. Therefore, based
19 on the statistics for this account as well as the three-year rolling averages
20 and trend in recent years, the recommended net salvage for distribution
21 poles is negative 65 percent.⁷²

⁷² Spanos Direct 28:8-16.

1 Mr. Spanos's calculations for this account suffer from two serious flaws—first, it includes
2 his alteration of historic reimbursement amounts in gross salvage; and second, it takes no
3 steps to reduce prior high inflation rates that are included in his historic data. The correction
4 of these two problems in Mr. Spanos's net salvage data is displayed in Table 7 below.

Table 7

Account 364, Poles, Towers, and Fixtures Net Salvage			
	Mr. Spanos (p. 28 Testimony)	Actual Book	At 2% Annual Inflation
26 Years Avg.	-65%	-51%	-37%
5 Years Avg.	-91%	-68%	-49%

5 I recommend a future net salvage of -45% for Account 364, Poles, Towers, and Fixtures.
6 Of course, in arriving at my net salvage recommendations, I also included information
7 other than just the historic net salvage ratios. Among other things, I also considered
8 information provided in discovery, information gained during my field trip to OGE
9 facilities, my considerable knowledge and experience in depreciation, judgment, and other
10 relevant information.

11 **Q. HAVE YOU PERFORMED A NET SALVAGE ANALYSIS OF OTHER**
12 **ACCOUNTS?**

13 **A.** Yes. I performed a similar analysis for each mass account in which my future net salvage
14 recommendation differs from Mr. Spanos's future net salvage recommendation.

15 **Q. PLEASE COMPARE YOUR FUTURE NET SALVAGE RECOMMENDATION TO**
16 **MR. SPANOS'S FUTURE NET SALVAGE RECOMMENDATION FOR ALL**

1 **MASS ACCOUNT NET SALVAGE AND INTERIM NET SALVAGE IN WHICH**
 2 **THE TWO RECOMMENDATIONS DIFFER.**

3 Mr. Spanos’s future net salvage recommendations and my future net salvage
 4 recommendations are compared in Table 8, shown below.⁷³

Table 8

FUTURE NET SALVAGE RECOMMENDATION COMPARISON		
Account	OGE Proposed	AG Proposed
Other Production Plant (Interim Net Salvage)		
Account 343, Prime Movers	-5%	-3%
Transmission Plant		
Account 355, Poles & Fixtures	-70%	-65%
Account 356, Overhead Conductors & Devices	-60%	-35%
Distribution Plant		
Account 364, Poles, Towers, & Fixtures	-65%	-45%
Account 365, Overhead Conductors & Devices	-55%	-40%
Account 366, Underground Conduit	-20%	-10%
Account 367, Underground Conductors & Devices	-30%	-15%
Account 369, Services	-20%	-5%

5 **Q. PREVIOUSLY IN THIS TESTIMONY, YOU DISCUSSED REDUCING THE**
 6 **ABNORMALLY HIGH PAST INFLATION USING THE MATHEMATICAL**
 7 **PROCEDURE SET FORTH IN THE DEPRECIATION TEXTBOOK**

⁷³ Production plant terminal net salvage, resulting from differences in decommissioning costs, are discussed elsewhere in this testimony.

1 **DEPRECIATION SYSTEMS. ARE THERE ANY OTHER METHODS FOR**
2 **REDUCING ABNORMALLY HIGH PAST INFLATION RATES WHEN**
3 **ESTIMATING FUTURE NET SALVAGE?**

4 A. Yes. To effectively reduce in the future net salvage ratio the abnormally high past inflation
5 contained in the historic net salvage ratio, a common practice is to recommend a future net
6 salvage ratio that is significantly lower than shown by the historic net salvage data. For
7 example, even a depreciation witness for a utility recommends a future net salvage ratio
8 that is between one-third to one-half of the ratio shown by the historic net salvage ratio.
9 This is done to effectively reduce the inflation rate that is included in the future net salvage
10 ratio.⁷⁴

11 **Q. FOR ACCOUNT 364, POLES, TOWERS, AND FIXTURES, DID MR. SPANOS, IN**
12 **HIS VERSION OF THE “TRADITIONAL” NET SALVAGE ANALYSIS, REDUCE**
13 **THE HIGH PAST INFLATION BY RECOMMENDING FUTURE NET SALVAGE**
14 **RATIOS THAT ARE BETWEEN A THIRD TO A HALF OF THE HISTORIC NET**
15 **SALVAGE RATIOS?**

16 A. No. Between a third to a half of the historic net salvage ratios would be between 33 percent
17 and 50 percent of the historic net salvage ratios. For Account 364, the booked historic net
18 salvage ratio for the investment that retired in the last 5 years averages –68 percent. Mr.
19 Spanos proposes a –65 percent future net salvage ratio, which is 96 percent of the historic
20 net salvage ratio for investment that retires during the most recent 5 years. His

⁷⁴ Tr. 13:10–14:3, *In re Northern Utilities, Inc. d/b/a Unitil*, No. 2017-00065 (Me. Pub. Utils. Comm’n Mar. 1, 2018), attached in excerpt form as Ex. WWD-25 (emphasis added).

1 recommended future net salvage ratio is not between a third to a half of the historic net
2 salvage ratio.

3 As previously discussed, Mr. Spanos had altered the booked data, and after that alteration
4 he was showing a -91 percent historic net salvage ratio for the investment that retired in
5 the last 5 years. Even using his altered historic data, the -65 percent future net salvage ratio
6 Mr. Spanos proposes is 71 percent of the (altered) 5-year historic net salvage ratio.

7 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.**

8 A. The historic net salvage data includes the impact of high past inflation which occurred
9 between the year the investments were installed and they year they retired. Mr. Spanos has
10 effectively assumed such high inflation will occur in the future, which is inconsistent with
11 the actual data in the past two decades. *Depreciation Systems* provides the correct detailed
12 mathematical way to adjust the historic data to a more reasonable level of inflation for
13 purposes of estimating future net salvage.

14 Another accepted method to reduce the high inflation that is included in the historic data
15 alternative is to recommend a future net salvage that is between a third to a half of the
16 historic net salvage ratios. Mr. Spanos did neither. Mr. Spanos' proposed future net salvage
17 ratios would charge ratepayer based upon the pure *assumption* that inflation will be in
18 excess of 10 percent per year in some years in the future.

1 **VI. PRODUCTION PLANT DEMOLITION ESTIMATES**

2 **Q. WHAT DECOMMISSIONING COSTS DID MR. SPANOS USE FOR**
3 **PRODUCTION UNITS?**

4 A. Mr. Spanos relied on decommissioning cost studies developed by Jeffrey T. Kopp to derive
5 net salvage values for production units. Mr. Spanos shows the estimated decommissioning
6 costs in current dollars on column 2 of page VIII-4 of his depreciation study.⁷⁵

7 **Q. WERE DEMOLITION COST STUDIES COSTS PRESENTED IN THE PRIOR**
8 **OGE PROCEEDING?**

9 A. No. Demolition cost studies were not filed in the prior OGE proceeding, Cause No. PUD
10 201500273.⁷⁶

11 **1. CONTINGENCY COSTS**

12 **Q. DID OGE INCLUDE CONTINGENCY COSTS IN ITS ESTIMATED**
13 **DECOMMISSIONING COSTS?**

14 A. Yes. Mr. Kopp described the inclusion of contingency costs in his testimony:
15 In addition to these direct costs, indirect costs are added to cover cost
16 incurred by the Company in executing the projects, *and contingency is*
17 *added to account for unknown, but reasonably expected to be incurred*
18 *costs.*⁷⁷

⁷⁵ Spanos Direct, Ex. JJS-2, at VIII-4.

⁷⁶ Final Order, Attachment 2, at 57–58, Order No. 662,059, *Okla. Gas & Elec. Co. Rates, Charges, & Tariffs for Retail Elec. Serv.*, No. PUD 201500273 (Okla. Corp. Comm’n Mar. 20, 2017).

⁷⁷ Kopp Direct 6:13–15.

1 Q. TURNING TO THE RECENT PSO PROCEEDING, DID THE COMMISSION
2 EXCLUDE CONTINGENCY COSTS IN THAT THE RECENT PSO
3 PROCEEDING?

4 A. Yes. The decommission costs adopted by the Commission in the recent PSO proceeding,
5 Cause No. PUD 201700151, *excluded* contingency costs.⁷⁸

6 Q. DID THE COMMISSION REJECT CONTINGENCY COSTS IN PSO'S PRIOR
7 RATE PROCEEDING?

8 A. Yes. Likewise, in the 2015 PSO rate case, Cause No. 201500208, the Commission rejected
9 contingency costs.⁷⁹

10 Q. ARE THE CLAIMED CONTINGENCY COSTS A SIGNIFICANT PART OF MR.
11 KOPP'S CLAIMED DECOMMISSIONING COST ESTIMATES?

12 A. Yes. Although the contingency costs are shown as a 20 percent adjustment, the way
13 contingency costs are actually applied in the calculations makes the contingency costs even
14 more significant than 20 percent. For example, in the Mustang CT decommissioning cost
15 estimate, the Contingency Costs are actually 38% of the claimed Total Net Project Cost
16 Estimate calculated by Mr. Kopp.⁸⁰

⁷⁸ See Final Order, Attachment 1, at 28, Order No. 672,864, *Pub. Serv. Co. of Okla. Rates & Charges for Elec. Serv.*, No. PUD 201700151 (Okla. Corp. Comm'n Jan. 31, 2018) ("THE COMMISSION FURTHER FINDS that the Attorney General's total demolition cost estimates are reasonable and appropriate and therefore adopt them in this Cause."); Responsive Test. of William W. Dunkel on Behalf of Mike Hunter, Oklahoma Attorney General 16:8-9, *Pub. Serv. Co. of Okla. Rates & Charges for Elec. Serv.*, No. PUD 201700151 (Okla. Corp. Comm'n Sept. 21, 2017) ("Contingency Costs . . . are not included in my decommissioning cost estimates.").

⁷⁹ See Final Order, Appendix A, at 164-65, Order No. 657,877, *Pub. Serv. Co. of Okla. Rates & Charges for Elec. Serv.*, No. PUD 201500208 (Okla. Corp. Comm'n Nov. 10, 2016).

⁸⁰ See Kopp Direct, Ex. JTK-1, Table B-7. The total net project cost to decommission the Mustang combustion turbines is shown as \$1,793,000, while the contingency costs are \$687,000, which is 38.32 percent of \$1,793,000.

1 **Q. WHAT IS ONE PROBLEM WITH INCLUDING CONTINGENCY COSTS?**

2 A. As stated in Mr. Kopp's testimony, the contingency costs are costs he adds to his cost
3 estimate "to account for unknown" costs.⁸¹ Requesting recovery of unknown costs is highly
4 speculative.

5 **Q. WHAT IS A SECOND PROBLEM WITH INCLUDING CONTINGENCY COSTS?**

6 A. As proposed by the Company, adding contingency costs is a one-sided adjustment. Since
7 the future is unknown, it is possible that something might occur in the future that would
8 result in costs higher than otherwise estimated by Mr. Kopp; however, it is *also* possible
9 that something might occur that would result in costs that are *lower* than otherwise
10 estimated by Mr. Kopp. Mr. Kopp's contingency adjustment includes only one of these
11 two possibilities. The Company's contingency costs are one-sided.

12 **Q. CAN YOU PROVIDE ONE EXAMPLE OF SOMETHING THAT COULD**
13 **REASONABLY OCCUR THAT WOULD RESULT IN COSTS THAT ARE**
14 **LOWER THAN OTHERWISE ESTIMATED BY MR. KOPP?**

15 A. Yes. One of Mr. Kopp's General Assumptions for All Sites was the following:

16 For purposes of this Study, it is assumed that none of the equipment will
17 have a salvage value in excess of the scrap value of the materials in the
18 equipment at the time of the decommissioning study. The decommissioning
19 cost estimate is based on the end of useful life of the facility. All equipment,
20 steel, copper, and other metals will be sold as scrap. Credits for salvage

⁸¹ Kopp Direct 6:13-15.

1 value are based on scrap value alone. Resale of equipment and materials is
2 not included.⁸²

3 If in the future any used equipment actually has a value greater than the “scrap value alone”
4 that would result in an actual net decommissioning cost *lower* than estimated by Mr. Kopp,
5 everything else being equal.

6 **Q. THE PRODUCTION UNITS WILL GENERALLY BE SEVERAL DECADES OLD**
7 **BY THE TIME OF FINAL RETIREMENT. DOES THAT MEAN THAT AT THE**
8 **TIME OF FINAL RETIREMENT, ALL OF THE EQUIPMENT WILL BE AS OLD**
9 **AS THE PRODUCTION UNIT?**

10 A. No. Due to interim retirements and replacements, at the time of final retirement, some of
11 the equipment in a production unit will be younger, and in some cases much younger, than
12 the overall life of the unit. For example, Mustang Unit 1 went into service in 1950 and
13 Mustang Unit 2 went into service in 1951.⁸³ However the Generator Step-Up (“GSU”)
14 Transformers in service for each of these units at the time of final retirement had both been
15 installed in the year 2000.⁸⁴ Neither of these Generator Step-Up Transformers (GSUs) were
16 scrapped. They were refurbished and are now in use on the new Mustang units 6 and 7.⁸⁵
17 Refurbishment and reuse of Mustang Unit 1 and Mustang Unit 2 GSUs saved

⁸² Kopp Direct, Ex. JTK-1, at 4–5.

⁸³ OGE Response to OIEC-OGE-8-1, including the attachment “OIEC 8-01_Att1.”

⁸⁴ OGE Response to AG-OGE-20-1, attached as Ex. WWD-26. A GSU Transformer is a large transformer that steps the power produced by the production unit’s generator up to the voltage to be delivered over transmission lines.

⁸⁵ OGE Response to AG-OGE-20-1, attached as Ex. WWD-26. At the retirement of Mustang Steam Production Units 3 and 4, there was also a transfer of \$4.1 million of Common Equipment and Land (Land was \$101,936 of this \$4.1 million amount) to the new Mustang CTs (Other Production Units). Also, \$8.3 million of depreciation reserve was transferred from the Sooner Steam Production Plant to the accounts for the retired Mustang Steam Production Units 3 and 4. See AG-OGE-7-10 and AG-OGE-19-20, attached as Ex. WWD-27.

1 approximately \$1 million as compared to new transformers.⁸⁶ The fact that the Mustang
2 Unit 1 and Mustang Unit 2 GSUs were not scrapped indicates that some equipment having
3 value greater than just scrapping it is a possibility for other future production unit final
4 retirements.⁸⁷

5 **Q. WHAT DO YOU RECOMMEND PERTAINING TO CONTINGENCY COSTS?**

6 A. I recommend that no contingency costs (in either direction) be included in
7 decommissioning cost estimates. This recommendation is consistent with my prior
8 testimony in PSO's recent rate case, Cause No. PUD 201700151, and with the
9 Commission's final order in the case, as described above.

10 **2. ESCALATION**

11 **Q. WHAT DOES MR. SPANOS DO WITH THE DECOMMISSIONING COST
12 ESTIMATES PROVIDE TO HIM BY MR. KOPP?**

13 A. Mr. Spanos increased the decommissioning cost estimates by 79 percent, on average—or
14 by about \$122,277,036 in total.⁸⁸ Mr. Spanos calls his proposed increase of the
15 decommissioning cost estimates “escalation.”⁸⁹

⁸⁶ OGE Response to AG-OGE-16-10, including the attachment “AG 16-10 Att.,” attached as Ex. WWD-28.

⁸⁷ Mr. Kopp did not include in his decommissioning cost estimates the costs to remove Mustang Unit 1 and Mustang Unit 2 GSUs, but he did generally include such costs, with scrap value credits, in his decommissioning cost estimates for other production units.

⁸⁸ See Spanos Direct, Ex. JJS-2, at VIII-4 (showing escalation of values in column (2) to values in column (3)).

⁸⁹ Spanos Direct 26:5–16.

1 **Q. WERE DEMOLITION COST STUDIES PRESENTED IN THE PRIOR OGE**
2 **PROCEEDING?**

3 A. No. As mentioned above, demolition cost studies were not filed in the prior OGE
4 proceeding, Cause No. PUD 201500273.⁹⁰

5 **Q. DID THE COMMISSION ADOPT ESCALATION OF THE DECOMMISSIONING**
6 **COSTS IN THE RECENT PSO PROCEEDING?**

7 A. No. The Commission specifically rejected the use of escalation.⁹¹

8 **Q. IN THE 2015 PSO RATE CASE, DID THE COMMISSION ADOPT**
9 **ESCALATION?**

10 A. No. The order entered in that case adopted the removal of escalation, as recommended by
11 the Administrative Law Judge.⁹²

12 **Q. COULD YOU DESCRIBE THE ESCALATION METHOD USED BY MR. SPANOS**
13 **IN THIS PROCEEDING?**

14 A. Yes. Using the Muskogee steam production plant as an example, Mr. Spanos started with
15 an estimated decommissioning cost of \$41,412,000 for the plant, developed by Mr. Kopp.
16 This estimate was in current dollars.⁹³

⁹⁰ See Final Order, Attachment 2, at 57–58, Order No. 662,059, *Okla. Gas & Elec. Co. Rates, Charges, & Tariffs for Retail Elec. Serv.*, No. PUD 201500273 (Okla. Corp. Comm’n Mar. 20, 2017).

⁹¹ See Final Order, Attachment 1, at 28, Order No. 672,864, *Pub. Serv. Co. of Okla. Rates & Charges for Elec. Serv.*, No. PUD 201700151 (Okla. Corp. Comm’n Jan. 31, 2018) (“[T]he Commission rejects Mr. Spanos’s escalation of the production plant demolition cost estimates.”).

⁹² See Final Order, Appendix A, at 164, Order No. 657,877, *Pub. Serv. Co. of Okla. Rates & Charges for Elec. Serv.*, No. PUD 201500208 (Okla. Corp. Comm’n Nov. 10, 2016) (recommending that escalation be rejected).

⁹³ Spanos Direct, Ex. JJS-2, at VIII-4.

1 Mr. Spanos estimated that current dollars will lose an average of 2.5 percent of their value
2 every year into the future.⁹⁴ Based on this assumption, a dollar in the year 2049 would be
3 worth only \$0.46, if the today's dollar is considered worth \$1.00. Because of the lower
4 value of the future dollars, Mr. Spanos calculated it would take \$89,755,602 of the future
5 dollars (worth \$0.46) to pay for the same demolition of the same plant for which Mr. Kopp
6 estimated the demolition would cost \$41,412,607 in today's more valuable dollar (worth
7 \$1.00). It is this \$89,755,602 estimate of decommissioning costs that Mr. Spanos
8 recommends spreading over the plant's remaining life to allow recovery from current
9 ratepayers for decommissioning Muskogee.

10 The \$89,755,602 decommissioning cost that Mr. Spanos used to calculate the amount he
11 proposes to collect from the current ratepayers is greatly inflated because it is calculated in
12 dollars that are worth \$0.46. However, the current ratepayers will *not* be paying for their
13 share of that cost in dollars worth \$0.46. Instead, current ratepayers would be paying in
14 dollars worth approximately \$1.00.⁹⁵ Nowhere in any of his calculations does Mr. Spanos
15 adjust for the fact that the \$82,025,706 decommissioning costs he uses for the Muskogee
16 plant is calculated in dollars worth \$0.46, while the rates that would be collected from
17 ratepayers would be collected in dollars worth approximately \$1.00.

⁹⁴ Spanos Direct 26:10.

⁹⁵ It is reasonable to expect that the rates that go into effect as a result of this proceeding will be applied for a limited number of future years in which the dollars can reasonably be expected to be worth close to, but somewhat less, than the value of the current dollar.

1 **Q. PLEASE EXPLAIN FURTHER THE PROBLEMS WITH MR. SPANOS’S**
2 **PROPOSED ESCALATION.**

3 A. As noted above, for the Muskogee steam production plant, Mr. Kopp estimated the
4 demolition would cost \$41,412,607 in today’s dollars. Mr. Spanos escalates this to be
5 \$89,755,602 by the year 2049. It is a portion of this \$89,755,602 spread over the years that
6 Mr. Spanos would charge current ratepayers. He treats an \$89 million cost expected to be
7 incurred over 3 decades in the future (in lower-value dollars) as if it were an \$89 million
8 cost payable today in today’s dollars. As an analogy, no reasonable ratepayer would
9 voluntarily pay \$10,000 today for a government savings bond that would be worth \$10,000
10 when it matures in 2049. However, that is similar to what Mr. Spanos is asking the
11 Commission to approve.

12 **Q. ARE YOU INCLUDING ESCALATION IN YOUR DECOMMISSIONING COST**
13 **ESTIMATES?**

14 A. No. For the reasons discussed above, and consistent with the Commission orders in No.
15 PUD 201500208 and No. PUD 201700151, I am not including escalation.

16 **VII. NEW FACILITIES AFTER DECEMBER 31, 2016**

17 **Q. DOES MR. SPANOS PROPOSE ANY NEW DEPRECIATION RATES FOR**
18 **PLANT PLACED IN SERVICE AFTER DECEMBER 31, 2016?**

19 A. Yes. He proposes “accrual rates for new facilities to be placed in service after December
20 31, 2016.”⁹⁶

⁹⁶ Spanos Direct, Ex. JJS-2, at VI-10.

1 **Q. WHAT IS THE STANDARD TREATMENT OF NEW INVESTMENTS THAT**
2 **OCCUR AFTER A DEPRECIATION STUDY HAS BEEN COMPLETED?**

3 A. The standard practice is that the approved depreciation accrual rate for an account also
4 applies to any new investments in an account. For example, assuming the depreciation
5 accrual rate approved in this proceeding is 2.40 percent for Account 364, Poles, Towers,
6 and Fixtures, all new investments in Account 364 would also depreciate at 2.40 percent
7 until the depreciation rate is changed in a future proceeding. I recommend this accepted
8 practice continue to apply in this proceeding.

9 **Q. UPON WHAT ARE THE NEW DEPRECIATION RATES THAT MR. SPANOS**
10 **PROPOSES FOR NEW FACILITIES PLACED IN SERVICE AFTER DECEMBER**
11 **31, 2016 BASED?**

12 A. These proposed rates are based upon numerous assumptions made by Mr. Spanos. These
13 assumptions are often one-sided or contrary to the evidence. For example, the “ACI Assets”
14 and “Muskogee Units 4 and 5” Mr. Spanos lists on page VI-10 relate to the planned
15 conversion of Muskogee Units 4 and 5 from coal-fired to natural-gas-fired. In his
16 workpapers related to the new investments, Mr. Spanos shows these new investments in
17 Muskogee Units 4 and 5 retiring in the year 2047.⁹⁷ However, elsewhere in his depreciation
18 study, Mr. Spanos calculates his proposed depreciation rates based on the assumption that
19 Muskogee Unit 4 will retire in 2042 and Muskogee Unit 5 will retire in 2043. In his “new
20 facilities” rates, Mr. Spanos is proposing to include some of the higher costs associated

⁹⁷ The 12-2047 “Probable Retirement Year” is shown on “AG-20-6-Muskogee4,5” provided by OGE in response to AG-OGE-20-6. These were the workpapers for the New Facilities rates on page VI-10 of Mr. Spanos’s depreciation study. Also, Mr. Spanos stated that the natural gas conversion would result in “a 30-year remaining service life,” which takes them approximately to 12-2047. Spanos Direct 30:1–2.

1 with the conversion from coal to gas, but in the rest of his depreciation study he is *not*
2 including the benefit of the longer life of Muskogee Units 4 and 5 he expects to result from
3 that conversion.⁹⁸

4 For another example of an assumption Mr. Spanos used in his “after the December 31,
5 2016” depreciation rates, Mr. Spanos assumes a life span of only 35 years for the new
6 Mustang combustion turbines.⁹⁹ Most of the other combustion turbines now in service or
7 that recently retired generally had, or are expected to have, a life span significantly longer
8 than 35 years.¹⁰⁰

9 **Q. WHAT DO YOU RECOMMEND PERTAINING TO THE NEW FACILITIES TO**
10 **BE PLACED IN SERVICE AFTER DECEMBER 31, 2016?**

11 A. I have followed the standard practice, which is that approved depreciation accrual rate for
12 an account also applies to new investments in an account. For example, the depreciation
13 rate proposed by the Attorney General for Account 343, Prime Movers, is 2.50 percent for
14 combustion turbines.¹⁰¹ If approved, this would also apply to new investments in Account
15 343 for combustion turbines until revised depreciation rates are adopted by this
16 Commission in a future proceeding.

⁹⁸ My recommended depreciation rates include *neither* the cost of new investments *nor* the longer life expected to result from conversion to natural gas.

⁹⁹ Spanos Direct 29:20.

¹⁰⁰ Horseshoe Lake 7 GT went into service in 1963 and retired in 2017 (54 years); both Tinker combustion turbines went into service in 1974 and OGE expects them to retire in 2025 (51 years); Seminole GT went into service in 1971 and retired in 2015 (44 years); McClain Gas Turbines 1 and 2 are expected to remain in service for 42 years; the Redbud Gas Turbines 1, 2, 3, and 4 are expected to live 45 years; for Horseshoe Lake Combustion turbines 9 and 10, the Company expects a life of 35 years. *See* OGE Response to OIEC-OGE-8-1; Spanos Direct, Ex. JJS-2, at III-7.

¹⁰¹ This account includes combustion turbines, but not other production like solar or wind facilities.

VIII. CONCLUSION

1
2 **Q. WHAT IS THE IMPACT OF MR. SPANOS’S PROPOSED CHANGES IN**
3 **DEPRECIATION RATES?**

4 A. The impact is significant. Mr. Spanos’s proposed depreciation rates would increase the
5 annual depreciation expense almost \$50 million. This is an 18 percent proposed increase
6 of the annual depreciation expense compared to current depreciation rates.

7 **Q. PLEASE COMPARE THE ANNUAL DEPRECIATION ACCRUALS MR. SPANOS**
8 **RECOMMENDS TO THE ANNUAL DEPRECIATION ACCRUALS YOU**
9 **RECOMMEND.**

10 A. The current depreciation rates, the depreciation rates Mr. Spanos recommends, and the
11 depreciation rates I am recommending on behalf of the Attorney General are shown on
12 Table 9 and Table 10 below.

Table 9
Comparison of Annual Accruals based on 12/31/2016 Investments

Functional Category	12/31/16 Investment	Accrual Amount at Current Rates	OGE Proposed Supplement Accrual Amount	OGE Proposed Difference from Current	AG Proposed Accrual Amount	AG Proposed Different from Current	AG Proposed Difference from Company
A	B	C	D	E=D-C	F	G=F-C	H=F-D
Intangible Plant	81,405,418	8,000,997	5,037,502	(2,963,495)	5,037,502	(2,963,495)	0
Steam Production	2,040,036,529	36,559,036	61,274,479	24,715,443	43,070,209	6,511,173	(18,204,270)
Other Production	1,532,424,575	59,829,580	59,940,673	111,093	54,801,923	(5,027,657)	(5,138,750)
Transmission Plt.	2,495,409,574	49,730,703	60,923,367	11,192,664	57,343,417	7,612,714	(3,579,950)
Distribution Plant	3,884,984,490	101,507,091	113,885,762	12,378,671	96,549,465	(4,957,626)	(17,336,297)
General Plant	367,462,831	14,580,395	17,836,292	3,255,897	17,836,292	3,255,897	0
General Plant Resr. Amort.			1,151,200	1,151,200	1,151,200	1,151,200	0
Total Depreciable Plant	10,401,723,416	270,207,802	320,049,275	49,841,473	275,790,008	5,582,206	(44,259,267)

Table 10
Comparison of Depreciation Annual Rates

Functional Category	12/31/16 Investment	Current Approved Depreciation Rate	OGE Proposed Supplement Depreciation Rate	OGE Proposed Difference from Current	AG Proposed Depreciation Rate	AG Proposed Different from Current	AG Proposed Difference from Company
A	B	C	D	E=D-C	F	G=F-C	H=F-D
Intangible Plant	81,405,418	9.83%	6.19%	-3.64%	6.19%	-3.64%	0.00%
Steam Production Plant	2,040,036,529	1.79%	3.00%	1.21%	2.11%	0.32%	-0.89%
Other Production Plant	1,532,424,575	3.90%	3.91%	0.01%	3.58%	-0.33%	-0.34%
Transmission Plant	2,495,409,574	1.99%	2.44%	0.45%	2.30%	0.31%	-0.14%
Distribution Plant	3,884,984,490	2.61%	2.93%	0.32%	2.49%	-0.13%	-0.45%
General Plant	367,462,831	3.97%	4.85%	0.89%	4.85%	0.89%	0.00%
General Plant Res. Amort.							
Total Depreciable Plant	10,401,723,416	2.60%	3.08%	0.48%	2.65%	0.05%	-0.43%

1 **Q. WHAT DEPRECIATION ACCRUAL RATES DO YOU RECOMMEND?**

2 A. For the reasons discussed in this testimony, I recommend the depreciation accrual rates
 3 shown in the AG Proposed columns of Exhibit WWD-2.

4 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

5 A. Yes.

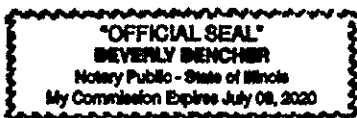
AFFIDAVIT OF WILLIAM W. DUNKEL

STATE OF ILLINOIS)
) ss
COUNTY OF SANGAMON)

I, William W. Dunkel, do hereby swear/affirm under penalty of perjury that the foregoing testimony is true and correct to the best of my knowledge and belief.

William W. Dunkel
William W. Dunkel

Subscribed and sworn to/affirmed before me this 2 day of May, 2018.



Beverly Bencher
Notary Public

My Commission expires on July 08, 2020.

CERTIFICATE OF SERVICE

On this 2nd day of May, 2018, a true and correct copy of the above and foregoing *Responsive Testimony of William W. Dunkel on Behalf of Mike Hunter, Oklahoma Attorney General*, along with attached exhibits, was sent via electronic mail to the following interested parties:

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Qualifications

William Dunkel is a consulting engineer specializing in utility regulatory proceedings. He has participated in over 250 state regulatory proceedings as listed on the attached Relevant Work Experience. Mr. Dunkel is a member of the Society of Depreciation Professionals.

Mr. Dunkel has provided cost analysis, rate design, jurisdictional separations, depreciation, expert testimony and other related services to state agencies throughout the country in numerous state regulatory proceedings.

Mr. Dunkel made a presentation pertaining to Current Depreciation Issues in State Rate Case Proceedings at the Society of Depreciation Professionals 25th Annual Meeting held September 2011 in Atlanta, GA.

Mr. Dunkel made a presentation pertaining to Video Dial Tone at the NASUCA 1993 Mid-Year Meeting held in St. Louis.

Mr. Dunkel made a presentation to the NARUC Subcommittee on Economics and Finance at the NARUC Summer Meetings held in July 1992. That presentation was entitled "The Reason the Industry Wants to Eliminate Cost Based Regulation--Telecommunications is a Declining Cost Industry."

Mr. Dunkel has testified before the Illinois House of Representatives Subcommittee on Communications, as well as participated in numerous other schools and conferences pertaining to the utility industry.

Mr. Dunkel provides services almost exclusively to public agencies, including the Public Utilities Commission, the Public Counsel, Office of Attorney General, or the State Department of Administration in various states.

William Dunkel currently provides, or in the past has provided, services in state utility regulatory proceedings to the following clients:

The Public Utility Commission or the Staffs in the States of:

Arkansas
Arizona
Delaware

Maryland
Mississippi
Missouri

District of Columbia	New Mexico
Georgia	North Carolina
Guam	Utah
Illinois	Virginia
Kansas	Washington
Maine	U.S. Virgin Islands

The Office of the Public Advocate, or its equivalent, in the States of:

Alaska	Maryland
California	Massachusetts
Colorado	Michigan
Connecticut	Missouri
District of Columbia	Nebraska
Florida	New Jersey
Georgia	New Mexico
Hawaii	Ohio
Illinois	Oklahoma
Indiana	Pennsylvania
Iowa	Utah
Maine	Washington

The Department of Administration in the States of:

Illinois	South Dakota
Minnesota	Wisconsin

Mr. Dunkel graduated from the University of Illinois in February 1970 with a Bachelor of Science Degree in Engineering Physics, with emphasis on economics and other business-related subjects. He has taken several post-graduate courses since graduation.

Mr. Dunkel has taken the AT&T separations school which is normally provided to AT&T personnel.

Mr. Dunkel has taken the General Telephone separations school which is normally provided for training of the General Telephone Company personnel in separations.

Mr. Dunkel has completed an advanced depreciation program entitled "Forecasting Life and Salvage" offered by Depreciation Programs, Inc.

From 1970 to 1974, Mr. Dunkel was a design engineer for Sangamo Electric Company (Sangamo was later purchased by Schlumberger) designing electric watt-hour meters used in the

electric utility industry. He was granted patent No. 3822400 for a solid state meter pulse initiator which was used in metering.

In April 1974, Mr. Dunkel was employed by the Illinois Commerce Commission in the Electric Section as a Utility Engineer. In November of 1975, he transferred to the Telephone Section of the Illinois Commerce Commission and from that time until July, 1980, he participated in essentially all telephone rate cases and other telephone rate matters that were set for hearing in the State of Illinois. During that period, he testified as an expert witness in numerous rate design cases and tariff filings in the areas of rate design, cost studies and separations. During the period 1975-1980, he was the Separations and Settlements expert for the Staff of the Illinois Commerce Commission.

From July 1977 until July 1980, Mr. Dunkel was a Staff member of the FCC-State Joint Board on Separations, concerning the "Impact of Customer Provision of Terminal Equipment on Jurisdictional Separations" in FCC Docket No. 20981 on behalf of the Illinois Commerce Commission. The FCC-State Joint Board is the national board that specifies the rules for separations in the telephone industry.

Since July 1980, Mr. Dunkel has been regularly employed as an independent consultant in state utility regulatory proceedings across the nation.

RELEVANT WORK EXPERIENCE OF
WILLIAM DUNKEL

ALASKA

- Golden Heart Utilities and College Utilities Corporation
 - Depreciation Rate Proceeding Docket No. U-15-089
- Chugach Electric
 - Depreciation Rate Proceeding Docket No. U-09-097
- Homer Electric
 - Depreciation Rate Proceeding Docket No. U-09-077
- TDX Sand Point Generating
 - Depreciation Rate Proceeding Docket No. U-09-029
- AWWU
 - Depreciation Rate Proceeding Docket No. U-08-004
- Enstar Natural Gas Company
 - Depreciation Rate Proceeding Docket No. U-07-174
- ML&P
 - Depreciation Rate Proceeding Docket No. U-12-149
 - Depreciation Rate Proceeding Docket No. U-06-006
- ACS of Anchorage
 - Docket No. U-01-34
- ACS
 - General rate case Docket Nos. U-01-83, U-01-85, U-01-87
 - AFOR proceeding Docket No. R-03-003
- All Telephone Companies
 - Access charge proceeding Docket No. R-01-001
- Interior Telephone Company
 - Docket No. U-07-75
- OTZ Telephone Cooperative
 - Docket No. U-03-85

ARIZONA

- Citizens Communications Company, Arizona Gas Division
 - Depreciation Rates Docket No. G-01032A-02
- U.S. West Communications (Qwest)
 - General Rate Case/Price Cap Renewal Docket No. T-01051B-03-0454
 - Wholesale cost/UNE case Docket No. T-00000A-00-0194
 - General rate case Docket No. E-1051-93-183
 - Depreciation case Docket No. T-01051B-97-0689
 - General rate case/AFOR proceeding Docket No. T-01051B-99-0105
 - AFOR proceeding Docket No. T-01051B-03-0454

ARKANSAS

- Southwestern Bell Telephone Company
 - Docket No. 83-045-U

CALIFORNIA

(on behalf of The Utility Reform Network (TURN))

- Southern California Edison Company Docket No. 16-09-001

(on behalf of the Office of Ratepayer Advocates (ORA))

- Kerman Telephone General Rate Case A.02-01-004

(on behalf of the California Cable Television Association)

- General Telephone of California I.87-11-033

- Pacific Bell
Fiber Beyond the Feeder Pre-Approval
Requirement

COLORADO

- Mountain Bell Telephone Company
General Rate Case Docket No. 96A-218T et al.
Call Trace Case Docket No. 92S-040T
Caller ID Case Docket No. 91A-462T
General Rate Case Docket No. 90S-544T
Local Calling Area Case Docket No. 1766
General Rate Case Docket No. 1720
General Rate Case Docket No. 1700
General Rate Case Docket No. 1655
General Rate Case Docket No. 1575
Measured Services Case Docket No. 1620

- Independent Telephone Companies
Cost Allocation Methods Case Docket No. 89R-608T

CONNECTICUT

- Southern Connecticut Gas Company
General Rate Case Docket No. 17-05-42

- Connecticut Light & Power
Depreciation Study Docket No. 17-10-46

- United Illuminating Company
General Rate Case Docket No. 16-06-04

DELAWARE

- Diamond State Telephone Company
General Rate Case PSC Docket No. 82-32
General Rate Case PSC Docket No. 84-33
Report on Small Centrex PSC Docket No. 85-32T
General Rate Case PSC Docket No. 86-20
Centrex Cost Proceeding PSC Docket No. 86-34

DISTRICT OF COLUMBIA

- Washington Gas Light Company
Depreciation issues Formal Case No. 1091 & 1093
- Potomac Electric Power Company
Depreciation issues Formal Case No. 1076
Depreciation issues Formal Case No. 1053
- C&P Telephone Company of D.C.
Depreciation issues Formal Case No. 926

FCC

- Review of jurisdictional separations FCC Docket No. 96-45
- Developing a Unified Intercarrier
Compensation Regime CC Docket No. 01-92

FLORIDA

- BellSouth, GTE, and Sprint
Fair and reasonable rates Undocketed Special Project

GEORGIA

- Atlanta Gas Light Company
General Rate Proceeding Docket No. 31647
- Southern Bell Telephone & Telegraph Co.
General Rate Proceeding Docket No. 3231-U
General Rate Proceeding Docket No. 3465-U
General Rate Proceeding Docket No. 3286-U
General Rate Proceeding Docket No. 3393-U

HAWAII

- GTE Hawaiian Telephone Company
Depreciation/separations issues Docket No. 94-0298
Resale case Docket No. 7702

ILLINOIS

- Commonwealth Edison Company
General Rate Proceeding Docket No. 80-0546
General Rate Proceeding Docket No. 82-0026
Section 50 Docket No. 59008
Section 55 Docket No. 59064
Section 50 Docket No. 59314
Section 55 Docket No. 59704
- Central Illinois Public Service
Section 55 Docket No. 58953

	Section 55	Docket No. 58999
	Section 55	Docket No. 59000
	Exchange of Facilities (Illinois Power)	Docket No. 59497
	General Rate Increase	Docket No. 59784
	Section 55	Docket No. 59677
-	South Beloit	
	General Rate Case	Docket No. 59078
-	Illinois Power	
	Section 55	Docket No. 59281
	Interconnection	Docket No. 59435
-	Verizon North Inc. and Verizon South Inc.	
	DSL Waiver Petition Proceeding	Docket No. 02-0560
-	Geneseo Telephone Company	
	EAS case	Docket No. 99-0412
-	Central Telephone Company	
	(Staunton merger)	Docket No. 78-0595
-	General Telephone & Electronics Co.	
	Usage sensitive service case	Docket Nos. 98-0200/98-0537
	General rate case (on behalf of CUB)	Docket No. 93-0301
	(Usage sensitive rates)	Docket No. 79-0141
	(Data Service)	Docket No. 79-0310
	(Certificate)	Docket No. 79-0499
	(Certificate)	Docket No. 79-0500
-	General Telephone Co.	Docket No. 80-0389
-	SBC	
	Imputation Requirement	Docket No. 04-0461
	Implement UNE Law	Docket No. 03-0323
	UNE Rate Case	Docket No. 02-0864
	Alternative Regulation Review	Docket No. 98-0252
-	Ameritech (Illinois Bell Telephone Company)	
	Area code split case	Docket No. 94-0315
	General Rate Case	Docket No. 83-0005
	(Centrex filing)	Docket No. 84-0111
	General Rate Proceeding	Docket No. 81-0478
	(Call Lamp Indicator)	Docket No. 77-0755
	(Com Key 1434)	Docket No. 77-0756
	(Card dialers)	Docket No. 77-0757
	(Concentration Identifier)	Docket No. 78-0005
	(Voice of the People)	Docket No. 78-0028
	(General rate increase)	Docket No. 78-0034
	(Dimension)	Docket No. 78-0086
	(Customer controlled Centrex)	Docket No. 78-0243
	(TAS)	Docket No. 78-0031

(Ill. Consolidated Lease)	Docket No. 78-0473
(EAS Inquiry)	Docket No. 78-0531
(Dispute with GTE)	Docket No. 78-0576
(WUI vs. Continental Tel.)	Docket No. 79-0041
(Carle Clinic)	Docket No. 79-0132
(Private line rates)	Docket No. 79-0143
(Toll data)	Docket No. 79-0234
(Dataphone)	Docket No. 79-0237
(Com Key 718)	Docket No. 79-0365
(Complaint - switchboard)	Docket No. 79-0380
(Porta printer)	Docket No. 79-0381
(General rate case)	Docket No. 79-0438
(Certificate)	Docket No. 79-0501
(General rate case)	Docket No. 80-0010
(Other minor proceedings)	Docket No. various
- Home Telephone Company	Docket No. 80-0220
- Northwestern Telephone Company	
Local and EAS rates	Docket No. 79-0142
EAS	Docket No. 79-0519

INDIANA

- Indiana-American Water Company	
Depreciation issues	Cause No. 44992
- Indiana Michigan Power Company (I&M)	
Depreciation issues	Cause No. 44075
Depreciation issues	Cause No. 42959
- Public Service of Indiana (PSI)	
Depreciation issues	Cause No. 39584
- Indianapolis Power and Light Company	
Depreciation issues	Cause No. 39938

IOWA

- U S West Communications, Inc.	
Local Exchange Competition	Docket No. RMU-95-5
Local Network Interconnection	Docket No. RPU-95-10
General Rate Case	Docket No. RPU-95-11

KANSAS

- Black Hills/Kansas Gas Utility Company	
General rate proceeding	Docket No. 14-BHCG-502-RTS
- Kansas Gas Services	
General rate proceeding	Docket No. 12-KGSG-838-RTS
- Westar Energy, Inc.	

	General rate proceeding	Docket No. 18-WSEE-328-RTS
	General rate proceeding	Docket No. 12-WSEE-112-RTS
	General rate proceeding	Docket No. 08-WSEE-1041-RTS
-	Midwest Energy, Inc.	
	General rate proceeding	Docket No. 11-MDWE-609-RTS
	General rate proceeding	Docket No. 08-MDWE-594-RTS
-	Generic Depreciation Proceeding	Docket No. 08-GIMX-1142-GIV
-	Kansas City Power & Light Company	
	General rate proceeding	Docket No. 15-KCPE-116-RTS
	General rate proceeding	Docket No. 12-KCPE-764-RTS
	General rate proceeding	Docket No. 10-KCPE-415-RTS
-	Atmos Energy Corporation	
	General rate proceeding	Docket No. 12-ATMG-564-RTS
	General rate proceeding	Docket No. 08-ATMG-280-RTS
-	Sunflower Electric Power Corporation	
	Depreciation rate study	Docket No. 08-SEPE-257-DRS
-	Southwestern Bell Telephone Company	
	Commission Investigation of the KUSF	Docket No. 98-SWBT-677-GIT
-	Rural Telephone Service Company	
	Audit and General rate proceeding	Docket No. 00-RRLT-083-AUD
	Request for supplemental KUSF	Docket No. 00-RRLT-518-KSF
-	Southern Kansas Telephone Company	
	Audit and General rate proceeding	Docket No. 01-SNKT-544-AUD
-	Pioneer Telephone Company	
	Audit and General rate proceeding	Docket No. 01-PNRT-929-AUD
-	Craw-Kan Telephone Cooperative, Inc.	
	Audit and General rate proceeding	Docket No. 01-CRKT-713-AUD
-	Sunflower Telephone Company, Inc.	
	Audit and General rate proceeding	Docket No. 01-SFLT-879-AUD
-	Bluestem Telephone Company, Inc.	
	Audit and General rate proceeding	Docket No. 01-BSST-878-AUD
-	Home Telephone Company, Inc.	
	Audit and General rate proceeding	Docket No. 02-HOMT-209-AUD
-	Wilson Telephone Company, Inc.	
	Audit and General rate proceeding	Docket No. 02-WLST-210-AUD
-	S&T Telephone Cooperative Association, Inc.	
	Audit and General rate proceeding	Docket No. 02-S&TT-390-AUD
-	Blue Valley Telephone Company, Inc.	
	Audit and General rate proceeding	Docket No. 02-BLVT-377-AUD
-	JBN Telephone Company	
	Audit and General rate proceeding	Docket No. 02-JBNT-846-AUD
-	S&A Telephone Company	
	Audit and General rate proceeding	Docket No. 03-S&AT-160-AUD

- Wheat State Telephone Company, Inc.
Audit and General rate proceeding Docket No. 03-WHST-503-AUD
- Haviland Telephone Company, Inc.
Audit and General rate proceeding Docket No. 03-HVDT-664-RTS

MAINE

- Northern Utilities, Inc. (Unitil)
General rate proceeding Docket No. 2017-065
- Emera
General rate proceeding Docket No. 2013-443
- Central Maine Power Company
General rate proceeding Docket No. 2013-168
General rate proceeding Docket No. 2007-125
- New England Telephone Company
General rate proceeding Docket No. 92-130
- Verizon
AFOR investigation Docket No. 2005-155

MARYLAND

- Washington Gas Light Company
Depreciation rate proceeding Case No. 9103
Depreciation Rate Case Case No. 8960
- Baltimore Gas and Electric Company
Depreciation rate proceeding Case No. 9355
Depreciation rate proceeding Case No. 9096
- PEPCO
General rate proceeding Case No. 9286
General rate proceeding Case No. 9217
General rate proceeding Case No. 9092
- Delmarva Power & Light Company
General rate proceeding Case No. 9285
- Chesapeake and Potomac Telephone Company
General rate proceeding Case No. 7851
Cost Allocation Manual Case Case No. 8333
Cost Allocation Issues Case Case No. 8462
- Verizon Maryland
PICC rate case Case No. 8862
USF case Case No. 8745
- Chesapeake Utilities Corporation
General rate proceeding Case No. 9062

MASSACHUSETTS

- Eversource Energy (NSTAR Electric Company and Western Massachusetts Electric Company)

- Depreciation Issues Case No. D.P.U. 17-005
- National Grid (Massachusetts Electric Company/Nantucket Electric Company) Depreciation Issues Case No. D.P.U. 15-155

MICHIGAN

- Wisconsin Electric Power Company Depreciation Rate Case Case No. U-15981
- SEMCO Energy Gas Company Depreciation Rate Case Case No. U-15778
- Michigan Consolidated Gas Company Depreciation Rate Case Case No. U-15699
- Consumers Energy Company Depreciation Rate Case Case No. U-15629

MINNESOTA

- Access charge (all companies) Docket No. P-321/CI-83-203
- U. S. West Communications, Inc. (Northwestern Bell Telephone Co.)
 - Centrex/Centron proceeding Docket No. P-421/91-EM-1002
 - General rate proceeding Docket No. P-321/M-80-306
 - Centrex Dockets MPUC No. P-421/M-83-466
 - MPUC No. P-421/M-84-24
 - MPUC No. P-421/M-84-25
 - MPUC No. P-421/M-84-26
 - MPUC No. P-421/GR-80-911
 - MPUC No. P-421/GR-82-203
 - MPUC No. P-421/GR-83-600
 - WATS investigation MPUC No. P-421/CI-84-454
 - Access charge case MPUC No. P-421/CI-85-352
 - Access charge case MPUC No. P-421/M-86-53
 - Toll Compensation case MPUC No. P-999/CI-85-582
 - Private Line proceeding Docket No. P-421/M-86-508
- AT&T
 - Intrastate Interexchange Docket No. P-442/M-87-54

MISSISSIPPI

- South Central Bell
 - General rate filing Docket No. U-4415

MISSOURI

- AmerenUE
 - Electric rate proceeding ER-2010-0036
 - Electric rate proceeding ER-2008-0318
- American Water Company

-	General rate proceeding	WR-2008-0311
-	Empire District Electric Company	
	Depreciation rates	ER-2008-0093
-	AmerenUE	
	Electric rate proceeding	ER-2007-0002
-	Southwestern Bell	
	General rate proceeding	TR-79-213
	General rate proceeding	TR-80-256
	General rate proceeding	TR-82-199
	General rate proceeding	TR-86-84
	General rate proceeding	TC-89-14, et al.
	Alternative Regulation	TC-93-224/TO-93-192
-	United Telephone Company	
	Depreciation proceeding	TR-93-181
-	All companies	
	Extended Area Service	TO-86-8
	EMS investigation	TO-87-131
	Cost of Access Proceeding	TR-2001-65
<u>NEBRASKA</u>		
-	SourceGas Distribution	
	Depreciation rate proceeding	NG-0079
<u>NEW JERSEY</u>		
-	Rockland Electric Company	
	General Rate Proceeding	BPU Docket No. ER16050428
-	New Jersey Natural Gas Company	
	General Rate Proceeding	BPU Docket No. GR15111304
-	South Jersey Gas Company	
	General Rate Proceeding	BPU Docket No. GR13111137
-	Atlantic City Electric Company	
	General Rate Proceeding	BPU Docket No. ER12121071 OAL Docket No. PUC00617-2013
-	New Jersey Bell Telephone Company	
	General rate proceeding	Docket No. 802-135
	General rate proceeding	BPU No. 815-458 OAL No. 3073-81
	Phase I - General rate case	BPU No. 8211-1030 OAL No. PUC10506-82
	General rate case	BPU No. 848-856 OAL No. PUC06250-84
	Division of regulated from competitive services	BPU No. TO87050398 OAL No. PUC 08557-87

Customer Request Interrupt

Docket No. TT 90060604

NEW MEXICO

- Public Service Company of New Mexico
 - Depreciation issues Case No. 15-00261-UT
 - Depreciation issues Case No. 10-00086-UT
 - Depreciation issues Case No. 08-00273-UT
- U.S. West Communications, Inc.
 - E-911 proceeding Case No. 92-79-TC
 - General rate proceeding Case No. 92-227-TC
 - General rate/depreciation proceeding Case No. 3008
 - Subsidy Case Case No. 3325
 - USF Case Case No. 3223
- VALOR Communications
 - Subsidy Case Case No. 3300
 - Interconnection Arbitration Case No. 3495

OHIO

- Ohio Bell Telephone Company
 - General rate proceeding Docket No. 79-1184-TP-AIR
 - General rate increase Docket No. 81-1433-TP-AIR
 - General rate increase Docket No. 83-300-TP-AIR
 - Access charges Docket No. 83-464-TP-AIR
- General Telephone of Ohio
 - General rate proceeding Docket No. 81-383-TP-AIR
- United Telephone Company
 - General rate proceeding Docket No. 81-627-TP-AIR

OKLAHOMA

- Public Service of Oklahoma
 - General Rate Case Cause No. PUD 201700151
 - Depreciation case Cause No. 96-0000214
- Oklahoma Gas and Electric Company
 - General Rate Case Cause No. PUD 201700496

PENNSYLVANIA

- GTE North, Inc.
 - Interconnection proceeding Docket No. A-310125F002
- Bell Telephone Company of Pennsylvania
 - Alternative Regulation proceeding Docket No. P-00930715
 - Automatic Savings Docket No. R-953409
 - Rate Rebalance Docket No. R-00963550
- Enterprise Telephone Company

- General rate proceeding Docket No. R-922317
- All companies
 - InterLATA Toll Service Invest. Docket No. I-910010
 - Joint Petition for Global Resolution of Telecommunications Proceedings Docket Nos. P-00991649, P-00991648, M-00021596
- GTE North and United Telephone Company
 - Local Calling Area Case Docket No. C-902815
- Verizon
 - Joint Application of Bell Atlantic and GTE for Approval of Agreement and Plan of Merger Docket Nos. A-310200F0002, A-311350F0002, A-310222F0002, A-310291F0003
 - Access Charge Complaint Proceeding Docket No. C-200271905

SOUTH DAKOTA

- Northwestern Bell Telephone Company
 - General rate proceeding Docket No. F-3375

TENNESSEE

- (on behalf of Time Warner Communications)
- BellSouth Telephone Company
 - Avoidable costs case Docket No. 96-00067

UTAH

- Questar Gas Company
 - Depreciation rate proceeding Docket No. 13-057-19
- Rocky Mountain Power
 - Depreciation rate proceeding Docket No. 13-035-02
- U.S. West Communications (Mountain Bell Telephone Company)
 - General rate case Docket No. 84-049-01
 - General rate case Docket No. 88-049-07
 - 800 Services case Docket No. 90-049-05
 - General rate case/
incentive regulation Docket No. 90-049-06/90-049-03
 - General rate case Docket No. 92-049-07
 - General rate case Docket No. 95-049-05
 - General rate case Docket No. 97-049-08
 - Qwest Price Flexibility-Residence Docket No. 01-2383-01
 - Qwest Price Flexibility-Business Docket No. 02-049-82
 - Qwest Price Flexibility-Residence Docket No. 03-049-49
 - Qwest Price Flexibility-Business Docket No. 03-049-50
- Carbon/Emery
 - General rate case/USF eligibility Docket No. 05-2302-01

VIRGIN ISLANDS, U.S.

- Virgin Islands Telephone Company
 - General rate case Docket No. 264
 - General rate case Docket No. 277
 - General rate case Docket No. 314
 - General rate case Docket No. 316

VIRGINIA

- General Telephone Company of the South
 - Jurisdictional allocations Case No. PUC870029
 - Separations Case No. PUC950019

WASHINGTON

- US West Communications, Inc.
 - Interconnection case Docket No. UT-960369
 - General rate case Docket No. UT-950200
- All Companies- Analyzed the local calling areas in the State

WISCONSIN

- Wisconsin Bell Telephone Company
 - Private line rate proceeding Docket No. 6720-TR-21
 - General rate proceeding Docket No. 6720-TR-34

Oklahoma Gas and Electric Company
 Table 1: Summary of Depreciation Rates and Annual Accrual Amounts
 As of December 31, 2016

Functional Category A	12/31/16 Depreciable Investment B	Current Approved		OGE Proposed-Supplemental Testimony			AG Proposed			
		Accrual Rate C	Accrual Amount D	Accrual Rate E	Accrual Amount F	Difference from Current G	Accrual Rate H	Accrual Amount I	Difference from Current J	Difference from Company K
Intangible Plant	81,405,418	9.83%	8,000,997	6.19%	5,037,502	(2,963,495)	6.19%	5,037,502	(2,963,495)	0
Steam Production Plant	2,040,036,529	1.79%	36,559,036	3.00%	61,274,479	24,715,443	2.11%	43,070,209	6,511,173	(18,204,270)
Other Production Plant	1,532,424,575	3.90%	59,829,580	3.91%	59,940,673	111,093	3.58%	54,801,923	(5,027,657)	(5,138,750)
Transmission Plant	2,495,409,574	1.99%	49,730,703	2.44%	60,923,367	11,192,664	2.30%	57,343,417	7,612,714	(3,579,950)
Distribution Plant	3,884,984,490	2.61%	101,507,091	2.93%	113,885,762	12,378,671	2.49%	96,549,465	(4,957,626)	(17,336,297)
General Plant	367,462,831	3.97%	14,580,395	4.85%	17,836,292	3,255,897	4.85%	17,836,292	3,255,897	0
General Plant Reserve Amortization					1,151,200	1,151,200		1,151,200	1,151,200	0
Total Depreciable Plant	10,401,723,416	2.60%	270,207,802	3.08%	320,049,275	49,841,473	2.65%	275,790,008	5,582,206	(44,259,267)

Oklahoma Gas and Electric Company
Table 2: Summary of Depreciation Rates and Annual Accrual Amounts
 As of December 31, 2016

Plant	12/31/16 Investment	Current Approved			OGE Proposed-Supplemental Testimony			AG Proposed			Difference from Company			
		Rate	Accrual Amount	D	Accrual Rate	Accrual Amount	F	Difference from Current	Accrual Rate	Accrual Amount		I	Difference from Current	J
Steam Production														
Horseshoe Lake 6	46,389,470	1.82%	843,833	6.69%	3,101,520	2,257,687	4.85%	2,249,744	1,405,911	(851,776)				
Horseshoe Lake 7	36,649,398	1.86%	681,362	2.38%	870,713	189,351	1.61%	591,275	(90,087)	(279,438)				
Horseshoe Lake 8	46,697,049	1.86%	867,856	3.01%	1,404,011	536,155	1.75%	819,395	(48,461)	(584,616)				
Mustang 3	18,821,382	1.87%	351,600	11.00%	2,070,922	1,719,322	0.23%	43,233	(308,367)	(2,027,689)				
Mustang 4	48,991,723	1.84%	903,462	10.23%	5,010,812	4,107,350	0.91%	444,604	(458,858)	(4,566,208)				
Seminole 1	108,333,295	1.83%	1,980,009	5.03%	5,449,560	3,469,551	3.02%	3,269,198	1,289,189	(2,180,362)				
Seminole 2	78,187,898	1.83%	1,427,484	4.87%	3,807,107	2,379,623	2.73%	2,130,862	703,378	(1,676,245)				
Seminole 3	91,190,455	1.81%	1,652,989	3.73%	3,397,151	1,744,162	1.82%	1,663,000	10,011	(1,734,151)				
Muskogee 4	306,310,015	1.80%	5,499,819	3.08%	9,435,140	3,935,321	2.79%	8,554,011	3,054,192	(881,129)				
Muskogee 5	197,825,189	1.79%	3,533,928	2.48%	4,901,944	1,368,016	2.19%	4,338,594	804,666	(563,350)				
Muskogee 6	441,315,161	1.78%	7,854,445	1.99%	8,775,846	921,401	1.75%	7,728,525	(125,920)	(1,047,321)				
Sooner 1	390,380,099	1.77%	6,901,649	2.14%	8,355,152	1,453,503	1.83%	7,149,540	247,891	(1,205,612)				
Sooner 2	227,497,199	1.77%	4,026,567	2.05%	4,670,110	643,543	1.79%	4,063,737	37,170	(606,373)				
Total Steam Production	2,038,588,331	1.79%	36,525,003	3.00%	61,249,988	24,724,985	2.11%	43,045,718	6,520,715	(18,204,270)				
Other Production Plant														
Redbud 1	147,889,651	3.45%	5,102,079	2.91%	4,298,532	(803,547)	2.26%	3,337,162	(1,764,917)	(961,370)				
Redbud 2	76,233,679	3.91%	2,979,747	3.29%	2,509,377	(470,370)	2.46%	1,873,753	(1,105,994)	(635,624)				
Redbud 3	75,962,557	3.91%	2,971,136	3.02%	2,296,378	(674,758)	2.26%	1,715,780	(1,255,356)	(580,598)				
Redbud 4	70,768,150	3.89%	2,754,508	3.12%	2,207,856	(546,652)	2.33%	1,645,890	(1,108,618)	(561,966)				
Horseshoe Lake 9 and 10	46,372,133	3.31%	1,535,671	3.63%	1,684,584	148,913	3.41%	1,582,437	46,766	(102,147)				
Tinker	11,395,007	3.34%	381,084	2.42%	276,108	(104,976)	2.06%	235,195	(145,889)	(40,913)				
McClain Gas 1	98,236,261	3.84%	3,774,869	3.41%	3,345,647	(429,222)	2.71%	2,666,195	(1,108,674)	(679,452)				
McClain Gas 2	77,725,653	4.00%	3,108,549	3.42%	2,656,605	(451,944)	2.61%	2,031,317	(1,077,232)	(625,288)				
McClain Steam 1	35,431,495	3.98%	1,411,570	3.15%	1,115,620	(295,950)	2.33%	825,774	(585,796)	(289,846)				
Total Other Production	640,014,587	3.75%	24,019,213	3.19%	20,390,707	(3,628,506)	2.49%	15,913,503	(8,105,710)	(4,477,204)				
Wind Production														
OU Spirit Wind Farm	249,929,539	4.12%	10,303,658	4.38%	10,956,009	652,351	4.33%	10,826,395	522,737	(129,614)				
Centennial Wind Farm	191,114,593	4.08%	7,790,434	4.31%	8,239,857	449,423	4.25%	8,123,861	333,427	(115,996)				
Crossroads Wind Farm	414,939,210	3.91%	16,209,250	4.11%	17,065,131	855,881	4.01%	16,655,591	446,341	(409,540)				
Total Wind Production	855,983,342	4.01%	34,303,342	4.24%	36,260,997	1,957,655	4.16%	35,605,848	1,302,506	(655,149)				
Solar Production														
Mustang Solar	6,771,150	4.34%	294,115	4.35%	294,285	170	4.25%	287,889	(6,226)	(6,396)				
Total Solar Production	6,771,150	4.34%	294,115	4.35%	294,285	170	4.25%	287,889	(6,226)	(6,396)				

Oklahoma Gas and Electric Company
 Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
 As of December 31, 2016

Account	Description A	Current Approved			OGE Proposed Supplemental Testimony			AG Proposed				
		12/31/16 Investment B	Accrual Rate C	Accrual Amount D	Accrual Rate E	Accrual Amount F	Difference from Current G	Accrual Rate H	Accrual Amount I	Difference from Current J	Difference from Company K	
INTANGIBLE PLANT												
301.00	Organization	80,900										
302.00	Franchises and Consents	2,414,266	4.22%	101,882	4.43%	107,032	5,150	4.43%	107,032	5,150	0	
303.20	Miscellaneous Intangible Plant - Software	78,991,152	10.00%	7,899,115	6.24%	4,930,470	(2,968,645)	6.24%	4,930,470	(2,968,645)	0	
	TOTAL INTANGIBLE PLANT	81,486,318	9.82%	8,000,997	6.18%	5,037,502	(2,963,495)	6.18%	5,037,502	(2,963,495)	0	
STEAM PRODUCTION PLANT												
310.10	Land											
	Horseshoe Lake 6	116,199										
	Mustang 4	101,936										
	Seminole 1	1,477,854										
	Muskogee 4	1,880,432										
	Sooner 1	7,006,282										
	Total Land	10,582,703										
310.20	Rights of Way											
	Horseshoe Lake 6	28,509	2.86%	815	1.07%	304	(511)	0.93%	266	(549)	(38)	
	Mustang 4	27,941	2.86%	799	0.00%	0	(799)	0.00%	0	(799)	0	
	Seminole 1	78,916	2.86%	2,257	2.11%	1,666	(591)	1.41%	1,115	(1,142)	(551)	
	Muskogee 4	18,934	2.86%	542	2.69%	510	(32)	2.69%	510	(32)	0	
	Sooner 1	813,704	2.86%	23,272	3.19%	25,989	2,717	3.19%	25,989	2,717	0	
	Total Rights of Way	968,005	2.86%	27,685	2.94%	28,469	784	2.88%	27,880	195	(589)	
311.00	Structures and Improvements											
	Horseshoe Lake 6	15,801,688	1.81%	286,011	8.43%	1,331,956	1,045,945	6.39%	1,009,777	723,766	(322,179)	
	Horseshoe Lake 7	2,757,683	1.81%	49,914	1.76%	48,441	(1,473)	1.07%	29,491	(20,423)	(18,950)	
	Horseshoe Lake 8	4,972,755	1.81%	90,007	2.07%	102,857	12,850	1.10%	54,917	(35,090)	(47,940)	
	Mustang 3	1,628,467	1.81%	29,475	8.55%	139,238	109,763	0.00%	0	(29,475)	(139,238)	
	Mustang 4	11,263,217	1.81%	203,864	4.31%	485,989	282,125	0.00%	0	(203,864)	(485,989)	
	Seminole 1	19,334,385	1.81%	349,952	3.56%	688,381	338,429	2.00%	387,409	37,457	(300,972)	
	Seminole 2	2,515,483	1.81%	45,530	3.70%	93,036	47,506	1.97%	49,667	4,137	(43,369)	
	Seminole 3	7,193,504	1.81%	130,202	2.96%	213,146	82,944	1.36%	98,044	(32,158)	(115,102)	
	Muskogee 4	42,323,393	1.81%	766,053	2.81%	1,190,805	424,752	2.53%	1,072,569	306,516	(118,236)	
	Muskogee 5	7,062,478	1.81%	127,831	2.29%	161,495	33,664	2.01%	142,253	14,422	(19,242)	
	Muskogee 6	51,734,198	1.81%	936,389	1.48%	766,680	(169,709)	1.26%	649,642	(286,747)	(117,036)	
	Sooner 1	92,130,299	1.81%	1,667,558	1.76%	1,621,117	(46,441)	1.46%	1,346,001	(321,557)	(275,116)	
	Sooner 2	12,443,474	1.81%	225,227	1.74%	216,757	(8,470)	1.49%	184,859	(40,368)	(31,898)	
	Total Structures and Improvements	271,161,023	1.81%	4,908,013	2.60%	7,059,898	2,151,885	1.85%	5,024,630	116,617	(2,035,268)	
312.00	Boiler Plant Equipment											

Oklahoma Gas and Electric Company
 Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
 As of December 31, 2016

Account	Description A	12/31/16 Investment B	Current Approved			OGE Proposed-Supplemental Testimony			AG Proposed			Difference from Company K
			Accrual Rate C	Accrual Amount D	Accrual Rate E	Accrual Amount F	Difference from Current G	Accrual Rate H	Accrual Amount I	Difference from Current J		
											Difference from Current K	
	Horseshoe Lake 6	17,172,926	1.71%	293,657	4.41%	756,772	463,115	2.85%	489,666	196,009	(267,106)	
	Horseshoe Lake 7	14,425,034	1.71%	246,668	2.26%	326,715	80,047	1.53%	220,461	(26,207)	(106,254)	
	Horseshoe Lake 8	18,937,831	1.71%	323,837	3.20%	605,485	281,648	1.89%	358,222	34,385	(247,263)	
	Mustang 3	6,594,326	1.71%	112,763	12.66%	834,552	721,789	0.66%	43,233	(69,530)	(791,319)	
	Mustang 4	17,554,423	1.71%	300,181	10.39%	1,823,373	1,523,192	0.00%	0	(300,181)	(1,823,373)	
	Seminole 1	51,896,789	1.71%	887,435	5.93%	3,076,640	2,189,205	3.62%	1,878,926	991,491	(1,197,714)	
	Seminole 2	42,764,010	1.71%	731,265	5.56%	2,378,996	1,647,731	3.15%	1,345,462	614,197	(1,033,534)	
	Seminole 3	48,100,089	1.71%	822,512	3.55%	1,707,479	884,967	1.71%	823,585	1,073	(883,894)	
	Seminole 4	155,515,022	1.71%	2,659,307	2.76%	4,287,449	1,628,142	2.47%	3,840,143	1,180,836	(447,306)	
	Muskogee 4	127,323,629	1.71%	2,177,234	2.53%	3,222,247	1,045,013	2.25%	2,864,906	687,672	(357,341)	
	Muskogee 5	252,184,492	1.71%	4,312,355	1.89%	4,766,683	454,328	1.66%	4,175,770	(136,585)	(590,913)	
	Muskogee 6	230,629,199	1.71%	3,943,759	2.31%	5,335,459	1,391,700	2.00%	4,621,727	677,968	(713,732)	
	Sooner 1	158,475,671	1.71%	2,709,934	2.07%	3,280,169	570,235	1.81%	2,864,572	154,638	(415,597)	
	Sooner 2	1,141,573,441	1.71%	19,520,907	2.84%	32,402,019	12,881,112	2.06%	23,526,674	4,005,767	(8,875,345)	
	Total Boiler Plant Equipment											
314.00	Turbogenerator Units											
	Horseshoe Lake 6	8,449,621	2.00%	168,992	7.35%	621,147	452,155	5.41%	457,118	288,126	(164,029)	
	Horseshoe Lake 7	16,213,969	2.00%	324,279	2.45%	397,596	73,317	1.66%	269,351	(54,928)	(128,245)	
	Horseshoe Lake 8	18,046,358	2.00%	360,927	3.07%	553,811	192,884	1.79%	323,323	(37,604)	(230,488)	
	Mustang 3	9,011,273	2.00%	180,225	10.20%	919,562	739,337	0.00%	0	(180,225)	(919,562)	
	Mustang 4	15,181,309	2.00%	303,626	14.93%	2,266,363	1,962,737	2.93%	444,604	140,978	(1,821,759)	
	Seminole 1	29,538,190	2.00%	590,764	4.62%	1,365,593	774,829	2.76%	814,548	223,784	(551,045)	
	Seminole 2	30,810,875	2.00%	616,218	4.09%	1,259,513	643,295	2.26%	695,140	78,922	(564,373)	
	Seminole 3	30,342,324	2.00%	606,846	4.27%	1,294,643	687,797	2.16%	655,154	48,308	(639,489)	
	Muskogee 4	65,638,797	2.00%	1,312,776	3.83%	2,515,279	1,202,503	3.54%	2,322,388	1,009,612	(192,891)	
	Muskogee 5	51,024,150	2.00%	1,020,483	2.48%	1,264,489	244,006	2.18%	1,113,651	93,168	(150,838)	
	Muskogee 6	89,914,590	2.00%	1,798,292	2.72%	2,448,823	650,531	2.47%	2,222,310	424,018	(226,513)	
	Sooner 1	37,211,499	2.00%	744,230	2.10%	783,093	38,863	1.78%	661,527	(82,703)	(121,566)	
	Sooner 2	41,787,368	2.00%	835,747	2.11%	879,628	43,881	1.82%	761,680	(74,067)	(117,948)	
	Total Turbogenerator Units	443,170,321	2.00%	8,863,405	3.74%	16,569,540	7,706,135	2.42%	10,740,794	1,877,389	(5,828,746)	
315.00	Accessory Electric Equipment											
	Horseshoe Lake 6	3,007,723	1.63%	49,026	8.07%	242,714	193,688	6.06%	182,386	133,360	(60,328)	
	Horseshoe Lake 7	2,213,598	1.63%	36,082	3.48%	76,975	40,893	2.65%	58,668	22,586	(18,307)	
	Horseshoe Lake 8	2,542,690	1.63%	41,446	3.43%	87,127	45,681	2.04%	51,810	10,364	(35,317)	
	Mustang 3	1,134,098	1.63%	18,486	11.28%	127,883	109,397	0.00%	0	(18,486)	(127,883)	
	Mustang 4	3,011,442	1.63%	49,087	9.10%	274,052	224,965	0.00%	0	(49,087)	(274,052)	
	Seminole 1	3,652,325	1.63%	59,533	4.43%	161,848	102,315	2.61%	95,390	35,857	(66,458)	
	Seminole 2	2,058,361	1.63%	33,551	3.53%	72,572	39,021	1.88%	38,752	5,201	(33,820)	
	Seminole 3	5,153,154	1.63%	83,996	3.23%	166,208	82,212	1.52%	78,343	(5,653)	(87,865)	
	Muskogee 4	34,025,650	1.63%	554,618	3.22%	1,094,083	539,465	2.94%	998,819	444,201	(95,264)	

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Account	Description A	Current Approved				OGE Proposed-Supplemental Testimony				AG Proposed			
		B	C	D	E	F	G	H	I	J	K		
	12/31/16 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current	Accrual Rate	Accrual Amount	Difference from Current	Difference from Company	
	11,579,336	1.63%	188,743	2.06%	238,219	49,476	1.77%	204,922	16,179	(33,297)			
Muskogee 5	42,835,435	1.63%	698,218	1.61%	690,684	(7,534)	1.38%	590,419	(107,799)	(100,265)			
Muskogee 6	23,980,815	1.63%	390,887	1.78%	425,986	35,099	1.46%	349,642	(41,245)	(76,344)			
Sooner 1	12,766,947	1.63%	208,101	1.88%	240,443	32,342	1.61%	205,831	(2,270)	(34,612)			
Sooner 2	147,961,574	1.63%	2,411,774	2.64%	3,898,794	1,487,020	1.93%	2,854,981	443,207	(1,043,813)			
Total Accessory Electric Equipment													
316.00	Miscellaneous Power Plant Equipment												
	Horseshoe Lake 6	1,929,002	2.35%	45,332	7.70%	148,627	103,295	5.73%	110,532	65,200	(38,095)		
	Horseshoe Lake 7	1,039,114	2.35%	24,419	2.02%	20,986	(3,433)	1.28%	13,304	(11,115)	(7,682)		
	Horseshoe Lake 8	2,197,415	2.35%	51,639	2.49%	54,731	3,092	1.42%	31,123	(20,516)	(23,608)		
	Mustang 3	453,218	2.35%	10,651	10.96%	49,687	39,036	0.00%	0	(10,651)	(49,687)		
	Mustang 4	1,953,391	2.35%	45,905	8.24%	161,035	115,130	0.00%	0	(45,905)	(161,035)		
	Seminole 1	3,832,690	2.35%	90,068	4.06%	155,432	65,364	2.40%	91,810	1,742	(63,622)		
	Seminole 2	39,168	2.35%	920	7.63%	2,990	2,070	4.70%	1,841	921	(1,149)		
	Seminole 3	401,384	2.35%	9,433	3.91%	15,675	6,242	1.96%	7,873	(1,560)	(7,802)		
	Muskogee 4	8,788,220	2.35%	206,523	3.95%	347,014	140,491	3.64%	319,582	113,059	(27,432)		
	Muskogee 5	835,596	2.35%	19,637	1.85%	15,494	(4,143)	1.54%	12,862	(6,775)	(2,632)		
	Muskogee 6	4,646,447	2.35%	109,191	2.22%	102,976	(6,215)	1.95%	90,383	(18,808)	(12,593)		
	Sooner 1	5,614,583	2.35%	131,943	2.91%	163,508	31,565	2.58%	144,653	12,710	(18,855)		
	Sooner 2	2,023,740	2.35%	47,558	2.62%	53,113	5,555	2.31%	46,796	(762)	(6,317)		
	Power Supply Services	1,448,198	2.35%	34,033	1.69%	24,491	(9,542)	1.69%	24,491	(9,542)	0		
	Total Miscellaneous Power Plant Equipment	35,202,165	2.35%	827,252	3.74%	1,315,759	488,507	2.54%	895,250	67,998	(420,509)		
TOTAL STEAM PRODUCTION PLANT		2,050,619,232	1.78%	36,559,036	2.99%	61,274,479	24,715,443	2.10%	43,070,209	6,511,173	(18,204,270)		
OTHER PRODUCTION PLANT													
340.00	Land												
	Redbud 1	326,890											
	McClain Gas 1	527,699											
	Total Land	854,589											
341.00	Structures and Improvements												
	Redbud 1	32,437,692	2.52%	817,430	2.41%	781,212	(36,218)	2.02%	656,065	(161,365)	(125,147)		
	Redbud 2	154,023	2.52%	3,881	3.14%	4,840	959	2.87%	4,414	533	(426)		
	Redbud 3	137,828	2.52%	3,473	3.14%	4,324	851	2.86%	3,940	467	(384)		
	Redbud 4	169,811	2.52%	4,279	3.08%	5,229	950	2.80%	4,754	475	(475)		
	Horseshoe Lake 9 and 10	987,208	2.52%	24,878	3.02%	29,770	4,892	2.76%	27,279	2,401	(2,491)		
	Tinker	972,164	2.52%	24,499	1.40%	13,648	(10,851)	1.06%	10,323	(14,176)	(3,325)		
	McClain Gas 1	8,326,702	2.52%	209,833	2.92%	242,818	32,985	2.63%	218,604	8,771	(24,214)		
	McClain Gas 2	959,632	2.52%	24,183	2.42%	23,231	(952)	2.04%	19,546	(4,637)	(3,685)		
	McClain Steam 1	528,864	2.52%	13,327	2.39%	12,643	(684)	2.06%	10,899	(2,428)	(1,744)		

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Account	Description A	Current Approved				OGE Proposed-Supplemental Testimony				AG Proposed			
		12/31/16 Investment B	Accrual		Difference from Current G	Accrual Rate E	Accrual		Difference from Current J	Accrual Rate H	Accrual		Difference from Company K
			Rate C	Amount D			Rate F	Amount I			Rate K	Amount L	
	Mustang Solar	700,769	4.04%	28,311	4.20%	29,465	1.154	28,813	4.11%	502	28,813	(652)	
	Total Structures and Improvements	45,374,693	2.54%	1,154,094	2.53%	1,147,180	(6,914)	984,637	2.17%	(169,457)	984,637	(162,543)	
341.00	Structures and Improvements - Wind												
	Centennial Wind Farm	2,382,899	4.32%	102,941	4.32%	102,969	28	101,250	4.25%	(1,691)	101,250	(1,719)	
	OU Spirit Wind Farm	5,209,833	4.08%	212,561	4.08%	212,523	(38)	209,172	4.01%	(3,389)	209,172	(3,351)	
	Crossroads Wind Farm	11,586,653	3.94%	456,514	3.94%	456,182	(332)	445,486	3.84%	(11,028)	445,486	(10,696)	
	Total Structures and Improvements - Wind	19,179,386	4.03%	772,016	4.02%	771,674	(342)	755,908	3.94%	(16,108)	755,908	(15,766)	
342.00	Fuel Holders, Producers, and Accessories												
	Redbud 1	12,118,339	2.19%	265,392	2.36%	286,413	21,021	257,207	2.12%	(8,185)	257,207	(29,206)	
	Redbud 2	690,650	2.19%	15,125	2.32%	16,025	900	14,347	2.08%	(778)	14,347	(1,678)	
	Redbud 3	691,291	2.19%	15,139	2.32%	16,046	907	14,366	2.08%	(773)	14,366	(1,680)	
	Redbud 4	718,677	2.19%	15,739	2.37%	17,037	1,298	15,322	2.13%	(417)	15,322	(1,715)	
	Tinker	167,150	2.19%	3,661	4.24%	7,080	3,419	6,517	3.90%	(563)	6,517	(563)	
	McClain Gas 1	249,233	2.19%	5,458	2.29%	5,699	241	5,174	2.08%	(525)	5,174	(525)	
	McClain Gas 2	166,187	2.19%	3,640	2.53%	4,201	561	3,855	2.32%	(284)	3,855	(346)	
	Total Fuel Holders, Producers, and Accessories	14,801,529	2.19%	324,154	2.38%	352,501	28,347	316,789	2.14%	(7,365)	316,789	(35,712)	
343.00	Prime Movers												
	Redbud 1	87,228,319	4.09%	3,567,638	3.26%	2,847,849	(719,789)	2,079,837	2.38%	(1,487,801)	2,079,837	(768,012)	
	Redbud 2	66,095,042	4.09%	2,703,287	3.46%	2,285,476	(417,811)	1,674,205	2.53%	(1,029,082)	1,674,205	(611,271)	
	Redbud 3	66,000,281	4.09%	2,699,411	3.15%	2,077,720	(621,691)	1,520,815	2.30%	(1,178,596)	1,520,815	(556,905)	
	Redbud 4	60,507,531	4.09%	2,474,758	3.28%	1,986,346	(488,412)	1,448,637	2.39%	(1,026,121)	1,448,637	(537,709)	
	Horseshoe Lake 9 and 10	5,529,837	4.09%	226,170	3.85%	212,808	(13,362)	181,646	3.28%	(44,524)	181,646	(31,162)	
	Tinker	3,909,265	4.09%	159,889	2.13%	83,126	(76,763)	67,381	1.72%	(92,508)	67,381	(15,745)	
	McClain Gas 1	81,288,521	4.09%	3,324,701	3.51%	2,853,969	(470,732)	2,219,320	2.73%	(1,105,381)	2,219,320	(694,649)	
	McClain Gas 2	72,644,774	4.09%	2,971,171	3.48%	2,527,059	(444,112)	1,914,596	2.64%	(1,056,575)	1,914,596	(612,463)	
	McClain Steam 1	32,684,810	4.09%	1,336,809	3.22%	1,050,975	(285,834)	766,991	2.35%	(569,818)	766,991	(283,984)	
	Total Prime Movers	475,888,379	4.09%	19,463,834	3.35%	15,925,328	(3,538,506)	11,873,429	2.50%	(7,590,405)	11,873,429	(4,051,899)	
L TSA													
343.10	5-Year												
	Redbud 1	2,129,176	4.09%	87,083	18.74%	398,996	311,913	398,996	18.74%	311,913	398,996	0	
	Redbud 2	1,786,505	4.09%	73,068	21.76%	388,662	315,594	388,662	21.76%	315,594	388,662	0	
	Redbud 3	1,908,402	4.09%	78,054	16.53%	315,405	237,351	315,405	16.53%	237,351	315,405	0	
	Redbud 4	2,141,159	4.09%	87,573	19.01%	407,002	319,429	407,002	19.01%	319,429	407,002	0	
	McClain Gas 1	8,126,360	4.09%	332,368	6.70%	544,060	211,692	544,060	6.70%	211,692	544,060	0	
	McClain Gas 2	7,601,183	4.09%	310,888	8.78%	667,079	356,191	667,079	8.78%	356,191	667,079	0	
	20-Year												
	Redbud 1	1,490,678	4.09%	60,969	4.47%	66,704	5,735	66,704	4.47%	5,735	66,704	0	

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		12/31/16 Investment B	Accrual Rate C	Accrual Amount D	Difference from Current G	Accrual Rate E	Accrual Amount F	Difference from Current G	Accrual Rate H	Accrual Amount I	Difference from Current J	Difference from Company K	
													Accrual Rate C
	Redbud 2	1,490,678	4.09%	60,969	24,468	5.73%	85,437	24,468	5.73%	85,437	24,468	0	
	Redbud 3	1,490,678	4.09%	60,969	(8,005)	3.55%	52,964	(8,005)	3.55%	52,964	(8,005)	0	
	Redbud 4	1,490,678	4.09%	60,969	7,406	4.59%	68,375	7,406	4.59%	68,375	7,406	0	
	Total LTSA	3,915,681	4.09%	160,151	627,507	20.12%	787,658	627,507	20.12%	787,658	627,507	0	
	Total Account 343	505,543,875	4.09%	20,676,744	(1,756,732)	3.74%	18,920,012	(1,756,732)	2.94%	14,868,113	(5,808,631)	(4,051,899)	
344.00	Generators												
	Redbud 1	717,739	3.29%	23,614	(807)	3.18%	22,807	(807)	2.95%	21,144	(2,470)	(1,663)	
	Redbud 3	23,199	3.29%	763	(42)	3.11%	721	(42)	2.88%	668	(95)	(53)	
	Redbud 4	23,035	3.29%	758	(43)	3.10%	715	(43)	2.87%	662	(96)	(53)	
	Horseshoe Lake 9 and 10	34,611,185	3.29%	1,138,708	142,878	3.70%	1,281,586	142,878	3.53%	1,222,185	83,477	(59,401)	
	Tinker	3,314,013	3.29%	109,031	7,376	3.51%	116,407	7,376	3.19%	105,601	(3,430)	(40,806)	
	Mustang Solar	4,750,812	4.47%	212,361	(3,087)	4.41%	209,274	(3,087)	4.31%	204,596	(7,765)	(4,678)	
	Total Generators	43,439,983	3.42%	1,485,235	146,275	3.76%	1,631,510	146,275	3.58%	1,554,856	69,621	(76,654)	
344.00	Generators - Wind												
	Centennial Wind Farm	186,823,660	4.06%	7,583,783	449,428	4.30%	8,033,211	449,428	4.24%	7,919,994	336,211	(113,217)	
	OU Spirit Wind Farm	243,118,184	4.12%	10,005,398	652,367	4.38%	10,657,765	652,367	4.33%	10,532,235	526,837	(125,530)	
	Crossroads Wind Farm	359,048,689	3.87%	13,903,302	854,989	4.11%	14,758,291	854,989	4.01%	14,399,915	496,613	(358,376)	
	Total Generators - Wind	788,990,533	3.99%	31,492,483	1,956,784	4.24%	33,449,267	1,956,784	4.16%	32,852,144	1,359,661	(597,123)	
345.00	Accessory Electric Equipment												
	Redbud 1	12,859,566	2.77%	356,210	(72,479)	2.21%	283,731	(72,479)	1.97%	252,825	(103,385)	(30,906)	
	Redbud 2	9,277,991	2.77%	257,000	(54,486)	2.18%	202,514	(54,486)	1.94%	180,305	(76,695)	(22,209)	
	Redbud 3	9,105,045	2.77%	252,210	(54,815)	2.17%	197,395	(54,815)	1.93%	175,830	(76,380)	(21,565)	
	Redbud 4	9,344,182	2.77%	258,834	(60,476)	2.12%	198,358	(60,476)	1.89%	176,356	(82,478)	(22,002)	
	Horseshoe Lake 9 and 10	4,302,451	2.77%	119,178	11,549	3.04%	130,727	11,549	2.87%	123,294	4,116	(7,433)	
	Tinker	3,023,751	2.77%	83,758	(28,139)	1.84%	55,619	(28,139)	1.49%	45,175	(38,583)	(40,444)	
	McClain Gas 1	4,116,839	2.77%	114,036	(1,081)	2.74%	112,955	(1,081)	2.52%	103,756	(10,280)	(9,199)	
	McClain Gas 2	3,955,059	2.77%	109,555	(7,441)	2.58%	102,114	(7,441)	2.36%	93,320	(16,235)	(8,794)	
	McClain Steam 1	2,217,821	2.77%	61,434	(9,432)	2.34%	52,002	(9,432)	2.16%	47,884	(13,550)	(4,118)	
	Mustang Solar	1,319,969	4.05%	53,443	2,103	4.21%	55,546	2,103	4.13%	54,480	1,037	(1,066)	
	Total Accessory Electric Equipment	59,522,275	2.80%	1,665,658	(274,697)	2.34%	1,390,961	(274,697)	2.11%	1,253,225	(412,493)	(137,736)	
345.00	Accessory Electric Equipment - Wind												
	Centennial Wind Farm	1,036,194	4.91%	50,877	(15)	4.91%	50,862	(15)	4.85%	50,251	(626)	(611)	
	OU Spirit Wind Farm	1,294,504	5.33%	68,997	8	5.33%	69,005	8	5.29%	68,419	(578)	(586)	
	Crossroads Wind Farm	43,987,182	4.17%	1,834,265	1,226	4.17%	1,835,491	1,226	4.08%	1,795,321	(38,944)	(40,170)	
	Total Accessory Electric Equipment - Wind	46,317,879	4.22%	1,954,139	1,219	4.22%	1,955,358	1,219	4.13%	1,913,990	(40,149)	(41,368)	

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 As of December 31, 2016

Account	Description A	Current Approved				OGE Proposed-Supplemental Testimony				AG Proposed			
		B	C	D	E	F	G	H	I	J	K		
	12/31/16 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current	Difference from Current	Difference from Company	
346.00	Miscellaneous Power Plant Equipment												
	Redbud 1	2,527,996	2.84%	71,795	3.03%	76,520	4,725	2.77%	70,083	(1,712)	(1,712)	(6,437)	
	Redbud 2	15,973	2.84%	454	3.27%	522	68	3.02%	482	28	28	(40)	
	Redbud 3	4,914	2.84%	140	3.50%	172	32	3.26%	160	20	20	(12)	
	Redbud 4	4,914	2.84%	140	3.48%	171	31	3.24%	159	19	19	(12)	
	Horseshoe Lake 9 and 10	941,452	2.84%	26,737	3.15%	29,693	2,956	2.98%	28,034	1,297	1,297	(1,659)	
	Tinker	8,664	2.84%	246	2.63%	228	(18)	2.28%	197	(49)	(49)	(31)	
	McClain Gas 1	4,254,965	2.84%	120,841	3.06%	130,206	9,365	2.80%	119,341	(1,500)	(1,500)	(10,865)	
	Total Miscellaneous Power Plant Equipment	7,758,877	2.84%	220,355	3.06%	237,512	17,159	2.82%	218,456	(1,897)	(1,897)	(19,056)	
346.00	Miscellaneous Power Plant Equipment - Wind												
	Centennial Wind Farm	871,840	6.06%	52,833	6.06%	52,815	(18)	6.01%	52,366	(467)	(467)	(449)	
	OU Spirit Wind Farm	307,018	5.44%	16,702	5.44%	16,716	14	5.40%	16,570	(132)	(132)	(146)	
	Crossroads Wind Farm	316,686	4.79%	15,169	4.79%	15,167	(2)	4.70%	14,869	(300)	(300)	(298)	
	Total Miscellaneous Power Plant Equipment - Wind	1,495,543	5.66%	84,704	5.66%	84,698	(6)	5.60%	83,806	(898)	(898)	(892)	
	TOTAL OTHER PRODUCTION PLANT	1,533,279,164	3.90%	59,829,580	3.91%	59,940,673	111,093	3.57%	54,801,923	(5,027,657)	(5,027,657)	(5,138,750)	
350.10	Land	3,737,687											
350.20	Land Rights	113,308,500	0.97%	1,099,092	1.35%	1,526,876	427,784	1.35%	1,526,876	427,784	427,784	0	
352.00	Structures and Improvements	6,702,508	1.67%	111,932	1.60%	106,993	(4,939)	1.60%	106,993	(4,939)	(4,939)	0	
353.00	Station Equipment												
	Station Equipment	667,860,982	1.75%	11,687,567	2.34%	15,619,120	3,931,553	2.34%	15,619,120	3,931,553	3,931,553	0	
353.10	Station Equipment - Step Up Transformers	53,026,203	1.75%	927,959	2.27%	1,203,074	275,115	2.27%	1,203,074	275,115	275,115	0	
	Total Station Equipment	720,887,185	1.75%	12,615,526	2.33%	16,822,194	4,206,668	2.33%	16,822,194	4,206,668	4,206,668	0	
354.00	Towers and Fixtures	161,794,747	1.40%	2,265,126	1.63%	2,630,663	365,537	1.63%	2,630,663	365,537	365,537	0	
355.00	Poles and Fixtures	903,252,386	2.23%	20,142,528	2.79%	25,185,996	5,043,468	2.69%	24,326,821	4,184,293	4,184,293	(859,175)	
356.00	Overhead Conductors and Devices	589,353,755	2.29%	13,496,201	2.49%	14,650,645	1,154,444	2.02%	11,929,870	(1,566,331)	(1,566,331)	(2,720,775)	
358.00	Underground Conductors and Devices	110,494	0.27%	298	0.00%	0	(298)	0.00%	0	(298)	(298)	0	
	TOTAL TRANSMISSION PLANT	2,489,147,261	1.99%	49,730,703	2.44%	60,923,367	11,192,664	2.29%	57,343,417	7,612,714	7,612,714	(3,579,950)	
360.10	Land	8,067,505											
360.20	Land Rights	5,107,131	0.90%	45,964	1.34%	68,501	22,537	1.34%	68,501	22,537	22,537	0	
361.00	Structures and Improvements	7,281,947	1.47%	107,045	1.42%	103,572	(3,473)	1.42%	103,572	(3,473)	(3,473)	0	
362.00	Station Equipment	615,608,481	1.83%	11,265,635	2.16%	13,310,342	2,044,707	2.16%	13,310,342	2,044,707	2,044,707	0	
364.00	Poles, Towers, and Fixtures	616,505,091	2.74%	16,892,239	2.85%	17,569,271	677,032	2.40%	14,776,711	(2,115,528)	(2,115,528)	(2,792,560)	

Oklahoma Gas and Electric Company
 Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
 As of December 31, 2016

Account	Description	Current Approved				OGE Proposed-Supplemental Testimony				AG Proposed			
		12/31/16 Investment	Accrual		Difference from Current	Accrual Rate	Accrual		Difference from Current	Accrual Rate	Accrual		Difference from Current
			Rate	Amount			Rate	Amount			Rate	Amount	
A	B	C	D	E	F	G	H	I	J	K			
365.00	Overhead Conductors and Devices	484,430,648	2.66%	12,885,855	2.69%	13,040,215	154,360	2.36%	11,416,932	(1,468,923)	(1,623,283)		
366.00	Underground Conduit	218,229,722	1.81%	3,949,958	1.80%	3,927,259	(22,699)	1.44%	3,135,824	(814,134)	(791,435)		
367.00	Underground Conductors and Devices	764,422,264	1.83%	13,988,927	1.98%	15,107,139	1,118,212	1.68%	12,826,990	(1,161,937)	(2,280,149)		
368.00	Line Transformers	455,509,839	2.82%	12,845,377	3.37%	15,337,358	2,491,981	3.37%	15,337,358	2,491,981	0		
369.00	Services	244,430,624	1.99%	4,864,169	1.76%	4,298,910	(565,259)	1.38%	3,360,993	(1,503,176)	(937,917)		
	Meters												
370.00	Meters - Smart Meters	143,337,370	6.70%	9,603,604	7.11%	10,189,577	585,973	5.10%	7,308,241	(2,295,363)	(2,881,336)		
370.01	Meters - Metering Equipment	37,150,057	5.85%	2,173,278	7.31%	2,715,071	541,793	7.31%	2,715,071	541,793	0		
	Total Meters	180,487,427	6.53%	11,776,882	7.15%	12,904,648	1,127,766	5.55%	10,023,312	(1,753,570)	(2,881,336)		
371.00	Installations on Customers' Premises	53,726,326	5.28%	2,836,750	9.75%	5,236,668	2,399,918	9.75%	5,236,668	2,399,918	0		
373.00	Street Lighting and Signal Systems	239,244,991	4.20%	10,048,290	5.43%	12,981,879	2,933,589	2.91%	6,952,262	(3,096,028)	(6,029,617)		
	TOTAL DISTRIBUTION PLANT	3,893,051,995	2.61%	101,507,091	2.93%	113,885,762	12,378,671	2.48%	96,549,465	(4,957,626)	(17,336,297)		
	GENERAL PLANT												
389.10	Land	3,002,965											
389.20	Land Rights	147,826	2.74%	4,050	2.06%	3,038	(1,012)	2.06%	3,038	(1,012)	0		
390.00	Structures and Improvements	178,876,850	1.52%	2,718,928	2.33%	4,174,936	1,456,008	2.33%	4,174,936	1,456,008	0		
	Office Furniture and Equipment												
391.00	Office Furniture and Equipment	13,996,151	8.61%	1,205,069	6.67%	933,878	(271,191)	6.67%	933,878	(271,191)	0		
391.10	Computer Equipment	16,150,015	8.61%	1,390,516	20.00%	3,230,541	1,840,025	20.00%	3,230,541	1,840,025	0		
	Total Office Furniture and Equipment	30,146,166	8.61%	2,595,585	13.81%	4,164,419	1,568,834	13.81%	4,164,419	1,568,834	0		
	Transportation Equipment												
392.10	Cars and Trucks	22,222,369	5.19%	1,153,341	6.08%	1,351,045	197,704	6.08%	1,351,045	197,704	0		
392.50	Heavy Trucks	59,365,922	5.19%	3,081,091	5.49%	3,256,893	175,802	5.49%	3,256,893	175,802	0		
392.60	Trailers	6,184,111	5.19%	320,955	3.47%	214,760	(106,195)	3.47%	214,760	(106,195)	0		
	Total Transportation Equipment	87,772,402	5.19%	4,555,387	5.49%	4,822,698	267,311	5.49%	4,822,698	267,311	0		
	Stores Equipment												
393.00	Stores Equipment	1,386,202	4.00%	55,448	4.00%	55,408	(40)	4.00%	55,408	(40)	0		
394.00	Tools, Shop, and Garage Equipment	11,609,251	4.00%	464,370	4.00%	464,079	(291)	4.00%	464,079	(291)	0		
395.00	Laboratory Equipment	12,071,163	5.00%	603,558	5.00%	603,434	(124)	5.00%	603,434	(124)	0		
396.00	Power Operated Equipment	12,650,956	4.86%	614,836	4.58%	579,926	(34,910)	4.58%	579,926	(34,910)	0		
397.00	Communication Equipment	26,562,653	10.00%	2,656,265	10.00%	2,656,107	(158)	10.00%	2,656,107	(158)	0		
398.00	Miscellaneous Equipment	6,239,362	5.00%	311,968	5.00%	312,247	279	5.00%	312,247	279	0		
	TOTAL GENERAL PLANT	370,465,796	3.94%	14,580,395	4.81%	17,836,292	3,255,897	4.81%	17,836,292	3,255,897	0		

Oklahoma Gas and Electric Company
 Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
 As of December 31, 2016

Account	Description A	12/31/16 Investment B	Current Approved		OGE Proposed-Supplemental Testimony			AG Proposed			Difference from Company K
			Accrual Rate C	Accrual Amount D	Accrual Rate E	Accrual Amount F	Difference from Current G	Accrual Rate H	Accrual Amount I	Difference from Current J	
RESERVE ADJUSTMENT FOR AMORTIZATION											
391.00	Office Furniture and Equipment			0			843,600	843,600	843,600	843,600	0
393.00	Stores Equipment				6,600		6,600	6,600	6,600	6,600	0
394.00	Tools, Shop, and Garage Equipment				117,000		117,000	117,000	117,000	117,000	0
395.00	Laboratory Equipment				338,600		338,600	338,600	338,600	338,600	0
397.00	Communication Equipment				102,000		102,000	102,000	102,000	102,000	0
398.00	Miscellaneous Equipment				(256,600)		(256,600)	(256,600)	(256,600)	(256,600)	0
TOTAL RESERVE ADJUSTMENT FOR AMORTIZATION				0			1,151,200	1,151,200	1,151,200	1,151,200	0
TOTAL DEPRECIABLE ELECTRIC PLANT		10,428,049,766	2.59%	270,207,802	3.07%	320,049,275	49,841,473	2.64%	275,790,008	5,582,206	(44,259,267)
ACCOUNTS NOT STUDIED											
Seminole GT											
Turbogenerator Units											
314.00											
ARO											
317.00	ARO for Steam Production	9,103,934									
347.00	ARO for Other Production	43,620,335									
359.00	ARO for Transmission	585,057									
TOTAL NONDEPRECIABLE PLANT		53,309,326		0			0		0	0	0
TOTAL ELECTRIC PLANT		10,481,359,092	2.58%	270,207,802	3.05%	320,049,275	49,841,473	2.63%	275,790,008	5,582,206	(44,259,267)

Note: Accrual Rates for Additions after December 31, 2016 accrue at the average depreciation rate for that account for that category plant as shown in the AG Proposed above. For example, for existing CTs the overall average depreciation rate for Account 344, Generators proposed by AG is 3.49%, which is the depreciation rate that would apply to new CT investments in Account 344. Generators made after December 31, 2016 until the depreciation rates are revised in future depreciation study.

Oklahoma Gas and Electric Company
Table 4: AG Calculation of Depreciation Rates
As of December 31, 2016

Account	Description	12/31/16 Investment	12/31/16 Book Reserve	Percent Reserve	Future Net Salvage Percent	Net Plant to be Recovered	Remaining Life	Total Annual Rate	Accrual
	A	B	C	D=C/B	E	F	G	H	I
INTANGIBLE PLANT									
301.00	Organization	80,900	0	0.00%	0%	80,900	0.0	0.00%	0
302.00	Franchises and Consents	2,414,266	1,387,832	57.48%	0%	1,026,434	9.6	4.43%	106,920
303.20	Miscellaneous Intangible Plant - Software	78,991,152	42,499,699	53.80%	0%	36,491,453	7.4	6.24%	4,931,277
	TOTAL INTANGIBLE PLANT	81,486,318	43,887,531			37,598,787			5,038,198
STEAM PRODUCTION PLANT									
310.10	Land								
	Horseshoe Lake 6	116,199	0	0.00%	0%	116,199	0.0	0.00%	0
	Mustang 4	101,936	0	0.00%	0%	101,936	0.0	0.00%	0
	Seminole 1	1,477,854	0	0.00%	0%	1,477,854	0.0	0.00%	0
	Muskogee 4	1,880,432	0	0.00%	0%	1,880,432	0.0	0.00%	0
	Sooner 1	7,006,282	0	0.00%	0%	7,006,282	0.0	0.00%	0
	Total Land	10,582,703	0			10,582,703			0
310.20	Rights of Way								
	Horseshoe Lake 6	28,509	26,384	92.55%	0%	2,125	8.0	0.93%	266
	Mustang 4	27,941	27,941	100.00%	0%	0	0.0	0.00%	0
	Seminole 1	78,916	55,613	70.47%	0%	23,303	20.9	1.41%	1,115
	Muskogee 4	18,934	5,739	30.31%	0%	13,195	25.9	2.69%	509
	Sooner 1	813,704	86,129	10.58%	0%	727,575	28.0	3.19%	25,985
	Total Rights of Way	968,005	201,806			766,199			27,875
311.00	Structures and Improvements								
	Horseshoe Lake 6	15,801,688	9,088,582	57.52%	-8%	7,977,241	7.9	6.39%	1,009,777
	Horseshoe Lake 7	2,757,683	2,634,285	95.53%	-9%	371,590	12.6	1.07%	29,491
	Horseshoe Lake 8	4,972,755	4,465,046	89.79%	-10%	1,004,984	18.3	1.10%	54,917
	Mustang 3	1,628,467	1,847,492	113.45%	-10%	(56,178)	1.0	0.00%	0
	Mustang 4	11,263,217	13,255,136	117.69%	-10%	(865,597)	1.0	0.00%	0
	Seminole 1	19,334,385	13,364,689	69.12%	-10%	7,903,134	20.4	2.00%	387,409
	Seminole 2	2,515,483	1,699,503	67.56%	-11%	1,092,683	22.0	1.97%	49,667
	Seminole 3	7,193,504	5,579,398	77.56%	-10%	2,333,456	23.8	1.36%	98,044
	Muskogee 4	42,323,393	18,364,553	43.39%	-7%	26,921,478	25.1	2.53%	1,072,569
	Muskogee 5	7,062,478	3,872,506	54.83%	-7%	3,684,346	25.9	2.01%	142,253
	Muskogee 6	51,734,198	35,669,065	68.95%	-8%	20,203,868	31.1	1.26%	649,642
	Sooner 1	92,130,299	62,641,184	67.99%	-7%	35,938,236	26.7	1.46%	1,346,001
	Sooner 2	12,443,474	8,373,828	67.29%	-8%	5,065,124	27.4	1.49%	184,859
	Total Structures and Improvements	271,161,023	180,855,267			111,574,364			5,024,630
312.00	Boiler Plant Equipment								
	Horseshoe Lake 6	17,172,926	14,727,368	85.76%	-8%	3,819,392	7.8	2.85%	489,666
	Horseshoe Lake 7	14,425,034	12,945,476	89.74%	-9%	2,777,811	12.6	1.53%	220,461
	Horseshoe Lake 8	18,937,831	14,383,618	75.95%	-10%	6,447,996	18.0	1.89%	358,222
	Mustang 3	6,594,326	7,210,525	109.34%	-10%	43,233	1.0	0.66%	43,233
	Mustang 4	17,554,423	19,593,026	111.61%	-10%	(283,161)	1.0	0.00%	0
	Seminole 1	51,896,789	19,695,832	37.95%	-10%	37,390,636	19.9	3.62%	1,878,926
	Seminole 2	42,764,010	18,406,076	43.04%	-11%	29,061,975	21.6	3.15%	1,345,462
	Seminole 3	48,100,089	33,885,282	70.45%	-10%	19,024,816	23.1	1.71%	823,585
	Muskogee 4	155,515,022	73,853,627	47.49%	-7%	92,547,446	24.1	2.47%	3,840,143
	Muskogee 5	127,323,629	64,613,632	50.75%	-7%	71,622,652	25.0	2.25%	2,864,906
	Muskogee 6	252,184,492	147,921,300	58.66%	-8%	124,437,951	29.8	1.66%	4,175,770
	Sooner 1	230,629,199	127,532,675	55.30%	-7%	119,240,568	25.8	2.00%	4,621,727
	Sooner 2	158,475,671	95,242,564	60.10%	-8%	75,911,160	26.5	1.81%	2,864,572
	Total Boiler Plant Equipment	1,141,573,441	650,011,001			582,042,476			23,526,674
314.00	Turbogenerator Units								
	Horseshoe Lake 6	8,449,621	5,697,207	67.43%	-8%	3,428,384	7.5	5.41%	457,118
	Horseshoe Lake 7	16,213,969	14,494,884	89.40%	-9%	3,178,342	11.8	1.66%	269,351
	Horseshoe Lake 8	18,046,358	14,225,179	78.83%	-10%	5,625,815	17.4	1.79%	323,323
	Mustang 3	9,011,273	10,074,192	111.80%	-10%	(161,791)	1.0	0.00%	0
	Mustang 4	15,181,309	16,254,835	107.07%	-10%	444,604	1.0	2.93%	444,604

Oklahoma Gas and Electric Company
Table 4: AG Calculation of Depreciation Rates
As of December 31, 2016

Account	Description A	12/31/16	12/31/16	Percent Reserve D=C/B	Future Net Salvage Percent E	Net Plant to be Recovered F	Remaining Life G	Total Annual Rate H	Total Annual Accrual I
		Investment B	Book Reserve C						
	Seminole 1	29,538,190	16,934,138	57.33%	-10%	15,557,871	19.1	2.76%	814,548
	Seminole 2	30,810,875	20,019,208	64.97%	-11%	14,180,864	20.4	2.26%	695,140
	Seminole 3	30,342,324	18,701,111	61.63%	-10%	14,675,445	22.4	2.16%	655,154
	Muskogee 4	65,638,797	15,657,396	23.85%	-7%	54,576,117	23.5	3.54%	2,322,388
	Muskogee 5	51,024,150	27,979,579	54.84%	-7%	26,616,261	23.9	2.18%	1,113,651
	Muskogee 6	89,914,590	35,105,304	39.04%	-8%	62,002,453	27.9	2.47%	2,222,310
	Sooner 1	37,211,499	23,807,349	63.98%	-7%	16,008,955	24.2	1.78%	661,527
	Sooner 2	41,787,368	26,088,367	62.43%	-8%	19,041,990	25.0	1.82%	761,680
	Total Turbogenerator Units	443,170,321	245,038,749			235,175,309			10,740,794
315.00	Accessory Electric Equipment								
	Horseshoe Lake 6	3,007,723	1,807,495	60.10%	-8%	1,440,846	7.9	6.06%	182,386
	Horseshoe Lake 7	2,213,598	1,673,604	75.61%	-9%	739,218	12.6	2.65%	58,668
	Horseshoe Lake 8	2,542,690	1,848,836	72.71%	-10%	948,123	18.3	2.04%	51,810
	Mustang 3	1,134,098	1,255,716	110.72%	-10%	(8,208)	1.0	0.00%	0
	Mustang 4	3,011,442	3,399,909	112.90%	-10%	(87,323)	1.0	0.00%	0
	Seminole 1	3,652,325	2,119,306	58.03%	-10%	1,898,252	19.9	2.61%	95,390
	Seminole 2	2,058,361	1,451,621	70.52%	-11%	833,160	21.5	1.88%	38,752
	Seminole 3	5,153,154	3,819,574	74.12%	-10%	1,848,895	23.6	1.52%	78,343
	Muskogee 4	34,025,650	11,936,372	35.08%	-7%	24,471,073	24.5	2.94%	998,819
	Muskogee 5	11,579,336	7,348,814	63.46%	-7%	5,041,075	24.6	1.77%	204,922
	Muskogee 6	42,835,435	28,726,824	67.06%	-8%	17,535,446	29.7	1.38%	590,419
	Sooner 1	23,980,815	16,848,495	70.26%	-7%	8,810,977	25.2	1.46%	349,642
	Sooner 2	12,766,947	8,416,117	65.92%	-8%	5,372,186	26.1	1.61%	205,831
	Total Accessory Electric Equipment	147,961,574	90,652,683			68,843,720			2,854,981
316.00	Miscellaneous Power Plant Equipment								
	Horseshoe Lake 6	1,929,002	1,232,226	63.88%	-8%	851,096	7.7	5.73%	110,532
	Horseshoe Lake 7	1,039,114	974,318	93.76%	-9%	158,316	11.9	1.28%	13,304
	Horseshoe Lake 8	2,197,415	1,894,288	86.21%	-10%	522,868	16.8	1.42%	31,123
	Mustang 3	453,218	503,239	111.04%	-10%	(4,700)	1.0	0.00%	0
	Mustang 4	1,953,391	2,222,103	113.76%	-10%	(73,373)	1.0	0.00%	0
	Seminole 1	3,832,690	2,535,838	66.16%	-10%	1,680,121	18.3	2.40%	91,810
	Seminole 2	39,168	9,047	23.10%	-11%	34,430	18.7	4.70%	1,841
	Seminole 3	401,384	269,886	67.24%	-10%	171,637	21.8	1.96%	7,873
	Muskogee 4	8,788,220	2,180,836	24.82%	-7%	7,222,559	22.6	3.64%	319,582
	Muskogee 5	835,596	604,694	72.37%	-7%	289,394	22.5	1.54%	12,862
	Muskogee 6	4,646,447	2,677,241	57.62%	-8%	2,340,922	25.9	1.95%	90,383
	Sooner 1	5,614,583	2,521,464	44.91%	-7%	3,486,140	24.1	2.58%	144,653
	Sooner 2	2,023,740	1,132,737	55.97%	-8%	1,052,902	22.5	2.31%	46,796
	Power Supply Services	1,448,198	407,685	28.15%	-5%	1,112,922	45.4	1.69%	24,514
	Total Miscellaneous Power Plant Equipment	35,202,165	19,165,602			18,845,234			895,273
	TOTAL STEAM PRODUCTION PLANT	2,050,619,232	1,185,925,108			1,027,830,005			43,070,227
	OTHER PRODUCTION PLANT								
340.00	Land								
	Redbud 1	326,890	0	0.00%	0%	326,890	0.0	0.00%	0
	McClain Gas 1	527,699	0	0.00%	0%	527,699	0.0	0.00%	0
	Total Land	854,589	0			854,589			0
341.00	Structures and Improvements								
	Redbud 1	32,437,692	12,744,773	39.29%	-3%	20,666,050	31.5	2.02%	656,065
	Redbud 2	154,023	15,180	9.86%	-3%	143,463	32.5	2.87%	4,414
	Redbud 3	137,828	13,918	10.10%	-3%	128,045	32.5	2.86%	3,940
	Redbud 4	169,811	20,412	12.02%	-3%	154,494	32.5	2.80%	4,754
	Horseshoe Lake 9 and 10	987,208	486,971	49.33%	-1%	510,109	18.7	2.76%	27,279
	Tinker	972,164	908,421	93.44%	-3%	92,908	9.0	1.06%	10,323
	McClain Gas 1	8,326,702	2,127,680	25.55%	-3%	6,448,823	29.5	2.63%	218,604
	McClain Gas 2	959,632	429,409	44.75%	-3%	559,012	28.6	2.04%	19,546
	McClain Steam 1	528,864	231,920	43.85%	-3%	312,810	28.7	2.06%	10,899
	Mustang Solar	700,769	43,435	6.20%	-2%	671,349	23.3	4.11%	28,813

Oklahoma Gas and Electric Company
Table 4: AG Calculation of Depreciation Rates
As of December 31, 2016

Account	Description	12/31/16 Investment	12/31/16 Book Reserve	Percent Reserve	Future Net Salvage Percent	Net Plant to be Recovered	Remaining Life	Total Annual Rate	Accrual
	A	B	C	D=C/B	E	F	G	H	I
	Total Structures and Improvements	45,374,693	17,022,119			29,687,063			984,637
341.00	Structures and Improvements - Wind								
	Centennial Wind Farm	2,382,899	898,101	37.69%	-1%	1,508,627	14.9	4.25%	101,250
	OU Spirit Wind Farm	5,209,833	1,517,760	29.13%	-1%	3,744,171	17.9	4.01%	209,172
	Crossroads Wind Farm	11,586,653	2,436,409	21.03%	-1%	9,266,111	20.8	3.84%	445,486
	Total Structures and Improvements - Wind	19,179,386	4,852,270			14,518,910			755,908
342.00	Fuel Holders, Producers, and Accessories								
	Redbud 1	12,118,339	5,022,892	41.45%	-3%	7,458,997	29.0	2.12%	257,207
	Redbud 2	690,650	295,311	42.76%	-3%	416,059	29.0	2.08%	14,347
	Redbud 3	691,291	295,404	42.73%	-3%	416,626	29.0	2.08%	14,366
	Redbud 4	718,677	295,892	41.17%	-3%	444,346	29.0	2.13%	15,322
	Tinker	167,150	113,509	67.91%	-3%	58,655	9.0	3.90%	6,517
	McClain Gas 1	249,233	106,662	42.80%	-3%	150,048	29.0	2.08%	5,174
	McClain Gas 2	166,187	60,151	36.19%	-3%	111,022	28.8	2.32%	3,855
	Total Fuel Holders, Producers, and Accessories	14,801,529	6,189,821			9,055,754			316,789
343.00	Prime Movers								
	Redbud 1	87,228,319	27,034,084	30.99%	-3%	62,811,084	30.2	2.38%	2,079,837
	Redbud 2	66,095,042	17,516,902	26.50%	-3%	50,560,991	30.2	2.53%	1,674,205
	Redbud 3	66,000,281	21,899,581	33.18%	-3%	46,080,708	30.3	2.30%	1,520,815
	Redbud 4	60,507,531	18,573,923	30.70%	-3%	43,748,834	30.2	2.39%	1,448,637
	Horseshoe Lake 9 and 10	5,529,837	2,261,014	40.89%	-1%	3,324,121	18.3	3.28%	181,646
	Tinker	3,909,265	3,426,848	87.66%	-3%	599,695	8.9	1.72%	67,381
	McClain Gas 1	81,288,521	21,364,293	26.28%	-3%	62,362,884	28.1	2.73%	2,219,320
	McClain Gas 2	72,644,774	21,598,347	29.73%	-3%	53,225,770	27.8	2.64%	1,914,596
	McClain Steam 1	32,684,810	12,879,902	39.41%	-3%	20,785,453	27.1	2.35%	766,991
	Total Prime Movers	475,888,379	146,554,894			343,499,540			11,873,429
	LTSA								
343.10	5-Year								
	Redbud 1	2,129,176	1,131,686	53.15%	0%	997,490	2.5	18.74%	398,996
	Redbud 2	1,786,505	814,851	45.61%	0%	971,654	2.5	21.76%	388,662
	Redbud 3	1,908,402	1,119,889	58.68%	0%	788,513	2.5	16.53%	315,405
	Redbud 4	2,141,159	1,123,655	52.48%	0%	1,017,504	2.5	19.01%	407,001
	McClain Gas 1	8,126,360	6,770,874	83.32%	0%	1,355,486	2.5	6.67%	542,194
	McClain Gas 2	7,601,183	5,946,925	78.24%	0%	1,654,258	2.5	8.71%	661,703
	20-Year								
	Redbud 1	1,490,678	990,395	66.44%	0%	500,283	7.5	4.47%	66,704
	Redbud 2	1,490,678	849,899	57.01%	0%	640,779	7.5	5.73%	85,437
	Redbud 3	1,490,678	1,093,451	73.35%	0%	397,227	7.5	3.55%	52,964
	Redbud 4	1,490,678	977,864	65.60%	0%	512,814	7.5	4.59%	68,375
	Total LTSA	3,915,681	20,819,489			1,969,144			787,658
	Total Account 343	505,543,875	167,374,383			352,335,547			14,860,871
344.00	Generators								
	Redbud 1	717,739	109,183	15.21%	-3%	630,088	29.8	2.95%	21,144
	Redbud 3	23,199	3,787	16.32%	-3%	20,108	30.1	2.88%	668
	Redbud 4	23,035	3,795	16.48%	-3%	19,931	30.1	2.87%	662
	Horseshoe Lake 9 and 10	34,611,185	13,202,403	38.14%	-1%	21,754,894	17.8	3.53%	1,222,185
	Tinker	3,314,013	2,484,146	74.96%	-3%	929,287	8.8	3.19%	105,601
	Mustang Solar	4,750,812	324,265	6.83%	-2%	4,521,564	22.1	4.31%	204,596
	Total Generators	43,439,983	16,127,579			27,875,872			1,554,856
344.00	Generators - Wind								
	Centennial Wind Farm	186,823,660	75,435,982	40.38%	-1%	113,255,915	14.3	4.24%	7,919,994
	OU Spirit Wind Farm	243,118,184	65,448,147	26.92%	-1%	180,101,219	17.1	4.33%	10,532,235
	Crossroads Wind Farm	359,048,689	76,080,872	21.19%	-1%	286,558,304	19.9	4.01%	14,399,915
	Total Generators - Wind	788,990,533	216,965,001			579,915,437			32,852,144

Oklahoma Gas and Electric Company
Table 4: AG Calculation of Depreciation Rates
As of December 31, 2016

Account	Description	12/31/16 Investment	12/31/16 Book Reserve	Percent Reserve	Future Net Salvage Percent	Net Plant to be Recovered	Remaining Life	Total Annual Rate	Accrual
	A	B	C	D=C/B	E	F	G	H	I
345.00	Accessory Electric Equipment								
	Redbud 1	12,859,566	5,862,856	45.59%	-3%	7,382,497	29.2	1.97%	252,825
	Redbud 2	9,277,991	4,291,428	46.25%	-3%	5,264,903	29.2	1.94%	180,305
	Redbud 3	9,105,045	4,261,535	46.80%	-3%	5,116,661	29.1	1.93%	175,830
	Redbud 4	9,344,182	4,316,192	46.19%	-3%	5,308,316	30.1	1.89%	176,356
	Horseshoe Lake 9 and 10	4,302,451	2,138,515	49.70%	-1%	2,206,961	17.9	2.87%	123,294
	Tinker	3,023,751	2,721,440	90.00%	-3%	393,023	8.7	1.49%	45,175
	McClain Gas 1	4,116,839	1,418,175	34.45%	-3%	2,822,170	27.2	2.52%	103,756
	McClain Gas 2	3,955,059	1,554,078	39.29%	-3%	2,519,633	27.0	2.36%	93,320
	McClain Steam 1	2,217,821	1,015,431	45.79%	-3%	1,268,925	26.5	2.16%	47,884
	Mustang Solar	1,319,569	82,022	6.22%	-2%	1,263,939	23.2	4.13%	54,480
	Total Accessory Electric Equipment	59,522,275	27,661,672			33,547,027			1,253,225
345.00	Accessory Electric Equipment - Wind								
	Centennial Wind Farm	1,036,194	312,894	30.20%	-1%	733,661	14.6	4.85%	50,251
	OU Spirit Wind Farm	1,294,504	110,123	8.51%	-1%	1,197,326	17.5	5.29%	68,419
	Crossroads Wind Farm	43,987,182	8,879,698	20.19%	-1%	35,547,356	19.8	4.08%	1,795,321
	Total Accessory Electric Equipment - Wind	46,317,879	9,302,715			37,478,343			1,913,990
346.00	Miscellaneous Power Plant Equipment								
	Redbud 1	2,527,996	697,566	27.59%	-3%	1,906,270	27.2	2.77%	70,083
	Redbud 2	15,973	2,769	17.34%	-3%	13,683	28.4	3.02%	482
	Redbud 3	4,914	467	9.50%	-3%	4,594	28.7	3.26%	160
	Redbud 4	4,914	473	9.63%	-3%	4,588	28.8	3.24%	159
	Horseshoe Lake 9 and 10	941,452	482,705	51.27%	-1%	468,162	16.7	2.98%	28,034
	Tinker	8,664	7,227	83.41%	-3%	1,697	8.6	2.28%	197
	McClain Gas 1	4,254,965	1,518,439	35.69%	-3%	2,864,175	24.0	2.80%	119,341
	Total Miscellaneous Power Plant Equipment	7,758,877	2,709,646			5,263,168			218,456
346.00	Miscellaneous Power Plant Equipment - Wind								
	Centennial Wind Farm	871,840	121,250	13.91%	-1%	759,308	14.5	6.01%	52,366
	OU Spirit Wind Farm	307,018	23,423	7.63%	-1%	286,665	17.3	5.40%	16,570
	Crossroads Wind Farm	316,686	22,468	7.09%	-1%	297,385	20.0	4.70%	14,869
	Total Miscellaneous Power Plant Equipment - W	1,495,543	167,141			1,343,358			83,806
	TOTAL OTHER PRODUCTION PLANT	1,533,279,164	468,372,347			1,091,875,068			54,794,681
	TRANSMISSION PLANT								
350.10	Land	3,737,687	0	0.00%	0%	3,737,687	0.0	0.00%	0
350.20	Land Rights	113,308,500	19,080,992	16.84%	0%	94,227,508	61.7	1.35%	1,527,188
352.00	Structures and Improvements	6,702,508	1,435,089	21.41%	-5%	5,602,545	52.4	1.60%	106,919
	Station Equipment								
353.00	Station Equipment	667,860,982	138,901,014	20.80%	-30%	729,318,262	46.7	2.34%	15,617,093
353.10	Station Equipment - Step Up Transformers	53,026,203	12,207,041	23.02%	-10%	46,121,782	38.3	2.27%	1,204,224
	Total Station Equipment	720,887,185	151,108,055			775,440,044			16,821,317
354.00	Towers and Fixtures	161,794,747	46,703,265	28.87%	-25%	155,540,168	59.1	1.63%	2,631,813
355.00	Poles and Fixtures	903,252,386	176,718,113	19.56%	-65%	1,313,648,323	54.0	2.69%	24,326,821
356.00	Overhead Conductors and Devices	589,353,755	147,835,617	25.08%	-35%	647,791,952	54.3	2.02%	11,929,870
358.00	Underground Conductors and Devices	110,494	110,976	100.44%	0%	(482)	0.0	0.00%	0
	TOTAL TRANSMISSION PLANT	2,499,147,261	542,992,107			2,995,987,746			57,343,929
	DISTRIBUTION PLANT								
360.10	Land	8,067,505	0	0.00%	0%	8,067,505	0.0	0.00%	0
360.20	Land Rights	5,107,131	1,518,013	29.72%	0%	3,589,118	52.4	1.34%	68,495
361.00	Structures and Improvements	7,281,947	2,011,103	27.62%	-5%	5,634,942	54.4	1.42%	103,583
362.00	Station Equipment	615,608,481	180,346,440	29.30%	-30%	619,944,585	46.6	2.16%	13,303,532
364.00	Poles, Towers, and Fixtures	616,505,091	239,324,082	38.82%	-45%	654,608,300	44.3	2.40%	14,776,711
365.00	Overhead Conductors and Devices	484,430,648	163,299,262	33.71%	-40%	514,903,645	45.1	2.36%	11,416,932
366.00	Underground Conduit	218,229,722	65,340,052	29.94%	-10%	174,712,643	55.7	1.44%	3,135,824

Oklahoma Gas and Electric Company
Table 4: AG Calculation of Depreciation Rates
As of December 31, 2016

Account	Description	12/31/16 Investment	12/31/16 Book Reserve	Percent Reserve	Future Net Salvage Percent	Net Plant to be Recovered	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D=C/B	E	F	G	H	I
367.00	Underground Conductors and Devices	764,422,264	232,605,300	30.43%	-15%	646,480,303	50.4	1.68%	12,826,990
368.00	Line Transformers	455,509,839	90,898,800	19.96%	-30%	501,263,991	32.7	3.37%	15,329,174
369.00	Services	244,430,624	124,565,148	50.96%	-5%	132,087,007	39.3	1.38%	3,360,993
	Meters								
370.00	Meters - Smart Meters	143,337,370	49,678,301	34.66%	-10%	107,992,806	14.8	5.10%	7,308,241
370.01	Meters - Metering Equipment	37,150,057	17,330,311	46.65%	-10%	23,534,752	8.7	7.28%	2,705,144
	Total Meters	180,487,427	67,008,612			131,527,558			10,013,385
371.00	Installations on Customers' Premises	53,726,326	29,720,800	55.32%	0%	24,005,526	4.6	9.71%	5,218,593
373.00	Street Lighting and Signal Systems	239,244,991	104,671,973	43.75%	-40%	230,271,014	33.1	2.91%	6,952,262
	TOTAL DISTRIBUTION PLANT	3,893,051,995	1,301,309,585			3,647,096,136			96,506,473
	GENERAL PLANT								
389.10	Land	3,002,965	0	0.00%	0%	3,002,965	0.0	0.00%	0
389.20	Land Rights	147,826	89,798	60.75%	0%	58,028	19.1	2.06%	3,038
390.00	Structures and Improvements	178,876,850	66,104,741	36.96%	-5%	121,715,951	29.2	2.33%	4,168,355
	Office Furniture and Equipment								
391.00	Office Furniture and Equipment	13,996,151	4,995,620	35.69%	0%	9,000,531	9.6	6.70%	937,555
391.10	Computer Equipment	16,150,015	2,638,683	16.34%	0%	13,511,332	4.2	19.92%	3,216,984
	Total Office Furniture and Equipment	30,146,166	7,634,303			22,511,863			4,154,539
	Transportation Equipment								
392.10	Cars and Trucks	22,222,369	12,803,387	57.61%	10%	7,196,745	5.3	6.11%	1,357,876
392.50	Heavy Trucks	59,365,922	28,321,338	47.71%	10%	25,107,992	7.7	5.49%	3,260,778
392.60	Trailers	6,184,111	1,673,874	27.07%	10%	3,891,826	18.1	3.48%	215,018
	Total Transportation Equipment	87,772,402	42,798,599			36,196,563			4,833,673
393.00	Stores Equipment	1,386,202	440,380	31.77%	0%	945,822	17.1	3.99%	55,311
394.00	Tools, Shop, and Garage Equipment	11,609,251	4,580,487	39.46%	0%	7,028,764	15.1	4.01%	465,481
395.00	Laboratory Equipment	12,071,163	5,835,115	48.34%	0%	6,236,048	10.3	5.02%	605,442
396.00	Power Operated Equipment	12,650,956	4,147,380	32.78%	15%	6,605,933	11.4	4.58%	579,468
397.00	Communication Equipment	26,562,653	12,033,427	45.30%	0%	14,529,226	5.5	9.95%	2,641,677
398.00	Miscellaneous Equipment	6,239,362	2,737,383	43.87%	0%	3,501,979	11.2	5.01%	312,677
	TOTAL GENERAL PLANT	370,465,796	146,401,613			222,333,142			17,819,660
	RESERVE ADJUSTMENT FOR AMORTIZATION								
391.00	Office Furniture and Equipment		(4,218,000)			4,218,000	5.0		843,600
393.00	Stores Equipment		(33,000)			33,000	5.0		6,600
394.00	Tools, Shop, and Garage Equipment		(585,000)			585,000	5.0		117,000
395.00	Laboratory Equipment		(1,693,000)			1,693,000	5.0		338,600
397.00	Communication Equipment		(510,000)			510,000	5.0		102,000
398.00	Miscellaneous Equipment		1,283,000			(1,283,000)	5.0		(256,600)
	TOTAL RESERVE ADJUSTMENT FOR AMORTIZATION		(5,756,000)			5,756,000			1,151,200
	TOTAL DEPRECIABLE ELECTRIC PLANT	10,428,049,766	3,683,132,291			9,028,476,883			275,724,368

Oklahoma Gas and Electric Company
 Table 5: Current and Proposed Parameters
 As of December 31, 2016

Account	Description	Current			OGE Proposed-Supplemental Testimony						AG Proposed				
		AYFR	Proj Life	Curve Shape	Future Net Salvage	AYFR	Proj Life	Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
INTANGIBLE PLANT															
301.00	Organization														
302.00	Franchises and Consents		25	SQ		25	SQ	9.6			25	SQ	9.6		
303.20	Miscellaneous Intangible Plant - Software		10	SQ		10	SQ	7.4			10	SQ	7.4		
TOTAL INTANGIBLE PLANT															
STEAM PRODUCTION PLANT															
310.10	Land														
	Horseshoe Lake 6														
	Mustang 4														
	Seminole 1														
	Muskogee 4														
	Sooner 1														
	Total Land														
310.20	Rights of Way														
	Horseshoe Lake 6		100	S4		2023	100	S4	7.0		2024	100	S4	8.0	
	Mustang 4		100	S4		2017	100	S4	0.0		2017	100	S4	0.0	
	Seminole 1		100	S4		2030	100	S4	14.0		2037	100	S4	20.9	
	Muskogee 4		100	S4		2042	100	S4	25.9		2042	100	S4	25.9	
	Sooner 1		100	S4		2044	100	S4	28.0		2044	100	S4	28.0	
	Total Rights of Way														
311.00	Structures and Improvements														
	Horseshoe Lake 6		100	R1.5	-2%	2023	105	R1.5	6.9	-16%	2024	105	R1.5	7.9	-8%
	Horseshoe Lake 7		100	R1.5	-3%	2028	105	R1.5	11.7	-16%	2029	105	R1.5	12.6	-9%
	Horseshoe Lake 8		100	R1.5	-3%	2029	105	R1.5	12.7	-16%	2035	105	R1.5	18.3	-10%
	Mustang 3		100	R1.5	-1%	2017	105	R1.5	1.0	-22%	2017	105	R1.5	1.0	-10%
	Mustang 4		100	R1.5	-1%	2017	105	R1.5	1.0	-22%	2017	105	R1.5	1.0	-10%
	Seminole 1		100	R1.5	-3%	2030	105	R1.5	13.7	-18%	2037	105	R1.5	20.4	-10%
	Seminole 2		100	R1.5	-3%	2030	105	R1.5	13.6	-18%	2039	105	R1.5	22.0	-11%
	Seminole 3		100	R1.5	-2%	2030	105	R1.5	13.6	-18%	2041	105	R1.5	23.8	-10%
	Muskogee 4		100	R1.5	-3%	2042	105	R1.5	25.1	-14%	2042	105	R1.5	25.1	-7%
	Muskogee 5		100	R1.5	-4%	2043	105	R1.5	25.9	-14%	2043	105	R1.5	25.9	-7%
	Muskogee 6		100	R1.5	-5%	2049	105	R1.5	31.1	-15%	2049	105	R1.5	31.1	-8%
	Sooner 1		100	R1.5	-4%	2044	105	R1.5	26.7	-15%	2044	105	R1.5	26.7	-7%
	Sooner 2		100	R1.5	-4%	2045	105	R1.5	27.4	-15%	2045	105	R1.5	27.4	-8%
	Total Structures and Improvements														
312.00	Boiler Plant Equipment														
	Horseshoe Lake 6		85	R0.5	-2%	2023	85	R0.5	6.9	-16%	2024	85	R0.5	7.8	-8%
	Horseshoe Lake 7		85	R0.5	-3%	2028	85	R0.5	11.6	-16%	2029	85	R0.5	12.6	-9%
	Horseshoe Lake 8		85	R0.5	-3%	2029	85	R0.5	12.5	-16%	2035	85	R0.5	18.0	-10%
	Mustang 3		85	R0.5	-1%	2017	85	R0.5	1.0	-22%	2017	85	R0.5	1.0	-10%
	Mustang 4		85	R0.5	-1%	2017	85	R0.5	1.0	-22%	2017	85	R0.5	1.0	-10%
	Seminole 1		85	R0.5	-3%	2030	85	R0.5	13.5	-18%	2037	85	R0.5	19.9	-10%
	Seminole 2		85	R0.5	-3%	2030	85	R0.5	13.5	-18%	2039	85	R0.5	21.6	-11%
	Seminole 3		85	R0.5	-2%	2030	85	R0.5	13.4	-18%	2041	85	R0.5	23.1	-10%
	Muskogee 4		85	R0.5	-3%	2042	85	R0.5	24.1	-14%	2042	85	R0.5	24.1	-7%
	Muskogee 5		85	R0.5	-4%	2043	85	R0.5	25.0	-14%	2043	85	R0.5	25.0	-7%
	Muskogee 6		85	R0.5	-5%	2049	85	R0.5	29.8	-15%	2049	85	R0.5	29.8	-8%
	Sooner 1		85	R0.5	-4%	2044	85	R0.5	25.8	-15%	2044	85	R0.5	25.8	-7%
	Sooner 2		85	R0.5	-4%	2045	85	R0.5	26.5	-15%	2045	85	R0.5	26.5	-8%
	Total Boiler Plant Equipment														
314.00	Turbogenerator Units														
	Horseshoe Lake 6		60	R1	-2%	2023	55	R1	6.6	-16%	2024	55	R1	7.5	-8%
	Horseshoe Lake 7		60	R1	-3%	2028	55	R1	10.8	-16%	2029	55	R1	11.8	-9%
	Horseshoe Lake 8		60	R1	-3%	2029	55	R1	12.1	-16%	2035	55	R1	17.4	-10%
	Mustang 3		60	R1	-1%	2017	55	R1	1.0	-22%	2017	55	R1	1.0	-10%
	Mustang 4		60	R1	-1%	2017	55	R1	1.0	-22%	2017	55	R1	1.0	-10%

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Account	Description	Current				OGE Proposed-Supplemental Testimony					AG Proposed				
		AYFR	lowa	Future	Net Salvage	AYFR	lowa	Avg	Future	AYFR	lowa	Avg	Future		
			Proj Life	Curve Shape			Proj Life	Curve Shape	Rem Life		Net Salvage	Proj Life	Curve Shape	Rem Life	Net Salvage
A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	
	Seminole 1	60	R1	-3%	2030	55	R1	13.1	-18%	2037	55	R1	19.1	-10%	
	Seminole 2	60	R1	-3%	2030	55	R1	13.0	-18%	2039	55	R1	20.4	-11%	
	Seminole 3	60	R1	-2%	2030	55	R1	13.2	-18%	2041	55	R1	22.4	-10%	
	Muskogee 4	60	R1	-3%	2042	55	R1	23.5	-14%	2042	55	R1	23.5	-7%	
	Muskogee 5	60	R1	-4%	2043	55	R1	23.9	-14%	2043	55	R1	23.9	-7%	
	Muskogee 6	60	R1	-5%	2049	55	R1	27.9	-15%	2049	55	R1	27.9	-8%	
	Sooner 1	60	R1	-4%	2044	55	R1	24.2	-15%	2044	55	R1	24.2	-7%	
	Sooner 2	60	R1	-4%	2045	55	R1	25.0	-15%	2045	55	R1	25.0	-8%	
	Total Turbogenerator Units														
315.00	Accessory Electric Equipment														
	Horseshoe Lake 6	70	R2.5	-2%	2023	75	R2	6.9	-16%	2024	75	R2	7.9	-8%	
	Horseshoe Lake 7	70	R2.5	-3%	2028	75	R2	11.6	-16%	2029	75	R2	12.6	-9%	
	Horseshoe Lake 8	70	R2.5	-3%	2029	75	R2	12.6	-16%	2035	75	R2	18.3	-10%	
	Mustang 3	70	R2.5	-1%	2017	75	R2	1.0	-22%	2017	75	R2	1.0	-10%	
	Mustang 4	70	R2.5	-1%	2017	75	R2	1.0	-22%	2017	75	R2	1.0	-10%	
	Seminole 1	70	R2.5	-3%	2030	75	R2	13.5	-18%	2037	75	R2	19.9	-10%	
	Seminole 2	70	R2.5	-3%	2030	75	R2	13.5	-18%	2039	75	R2	21.5	-11%	
	Seminole 3	70	R2.5	-2%	2030	75	R2	13.6	-18%	2041	75	R2	23.6	-10%	
	Muskogee 4	70	R2.5	-3%	2042	75	R2	24.5	-14%	2042	75	R2	24.5	-7%	
	Muskogee 5	70	R2.5	-4%	2043	75	R2	24.6	-14%	2043	75	R2	24.6	-7%	
	Muskogee 6	70	R2.5	-5%	2049	75	R2	29.7	-15%	2049	75	R2	29.7	-8%	
	Sooner 1	70	R2.5	-4%	2044	75	R2	25.2	-15%	2044	75	R2	25.2	-7%	
	Sooner 2	70	R2.5	-4%	2045	75	R2	26.1	-15%	2045	75	R2	26.1	-8%	
	Total Accessory Electric Equipment														
316.00	Miscellaneous Power Plant Equipment														
	Horseshoe Lake 6	45	R0.5	-2%	2023	50	R0.5	6.8	-16%	2024	50	R0.5	7.7	-8%	
	Horseshoe Lake 7	45	R0.5	-3%	2028	50	R0.5	11.0	-16%	2029	50	R0.5	11.9	-9%	
	Horseshoe Lake 8	45	R0.5	-3%	2029	50	R0.5	12.0	-16%	2035	50	R0.5	16.8	-10%	
	Mustang 3	45	R0.5	-1%	2017	50	R0.5	1.0	-22%	2017	50	R0.5	1.0	-10%	
	Mustang 4	45	R0.5	-1%	2017	50	R0.5	1.0	-22%	2017	50	R0.5	1.0	-10%	
	Seminole 1	45	R0.5	-3%	2030	50	R0.5	12.8	-18%	2037	50	R0.5	18.3	-10%	
	Seminole 2	45	R0.5	-3%	2030	50	R0.5	12.4	-18%	2039	50	R0.5	18.7	-11%	
	Seminole 3	45	R0.5	-2%	2030	50	R0.5	13.0	-18%	2041	50	R0.5	21.8	-10%	
	Muskogee 4	45	R0.5	-3%	2042	50	R0.5	22.6	-14%	2042	50	R0.5	22.6	-7%	
	Muskogee 5	45	R0.5	-4%	2043	50	R0.5	22.5	-14%	2043	50	R0.5	22.5	-7%	
	Muskogee 6	45	R0.5	-5%	2049	50	R0.5	25.9	-15%	2049	50	R0.5	25.9	-8%	
	Sooner 1	45	R0.5	-4%	2044	50	R0.5	24.1	-15%	2044	50	R0.5	24.1	-7%	
	Sooner 2	45	R0.5	-4%	2045	50	R0.5	22.5	-15%	2045	50	R0.5	22.5	-8%	
	Power Supply Services	45	R0.5	-2%		50	R0.5	45.4	-5%		50	R0.5	45.4	-5%	
	Total Miscellaneous Power Plant Equipment														
	TOTAL STEAM PRODUCTION PLANT														
	OTHER PRODUCTION PLANT														
340.00	Land														
	Redbud 1														
	McClain Gas 1														
	Total Land														
341.00	Structures and Improvements														
	Redbud 1	45	S4	-3%	2049	45	R4	29.4	-10%	2049	55	R4	31.5	-3%	
	Redbud 2	45	S4	-4%	2049	45	R4	31.9	-10%	2049	55	R4	32.5	-3%	
	Redbud 3	45	S4	-4%	2049	45	R4	31.8	-10%	2049	55	R4	32.5	-3%	
	Redbud 4	45	S4	-4%	2049	45	R4	31.8	-10%	2049	55	R4	32.5	-3%	
	Horseshoe Lake 9 and 10	45	S4	-1%	2035	45	R4	18.1	-4%	2035	55	R4	18.7	-1%	
	Tinker	45	S4	-1%	2025	45	R4	8.9	-6%	2025	55	R4	9.0	-3%	
	McClain Gas 1	45	S4	-4%	2046	45	R4	28.6	-9%	2046	55	R4	29.5	-3%	
	McClain Gas 2	45	S4	-4%	2046	45	R4	26.5	-9%	2046	55	R4	28.6	-3%	
	McClain Steam 1	45	S4	-4%	2046	45	R4	26.8	-8%	2046	55	R4	28.7	-3%	
	Mustang Solar	40	S3	0%	2040	40	S3	23.3	-4%	2040	40	S3	23.3	-2%	

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Account	Description	Current				OGE Proposed-Supplemental Testimony					AG Proposed			
		AYFR	lowa	Future	Net	AYFR	lowa	Avg	Future	AYFR	lowa	Avg	Future	
			Proj	Curve			Curve	Rem	Curve		Rem	Curve	Rem	
B	C	D	E	F	G	H	I	J	K	L	M	N	O	
Total Structures and Improvements														
341.00	Structures and Improvements - Wind													
	Centennial Wind Farm	45	S3	-1%	2031	45	S3	14.9	-2%	2031	45	S3	14.9	-1%
	OU Spirit Wind Farm	45	S3	-1%	2034	45	S3	17.9	-2%	2034	45	S3	17.9	-1%
	Crossroads Wind Farm	45	S3	-1%	2037	45	S3	20.8	-3%	2037	45	S3	20.8	-1%
Total Structures and Improvements - Wind														
342.00	Fuel Holders, Producers, and Accessories													
	Redbud 1	55	R4	-3%	2049	55	R4	29.0	-10%	2049	55	R4	29.0	-3%
	Redbud 2	55	R4	-4%	2049	55	R4	29.0	-10%	2049	55	R4	29.0	-3%
	Redbud 3	55	R4	-4%	2049	55	R4	29.0	-10%	2049	55	R4	29.0	-3%
	Redbud 4	55	R4	-4%	2049	55	R4	29.0	-10%	2049	55	R4	29.0	-3%
	Tinker	55	R4	-1%	2025	55	R4	9.0	-6%	2025	55	R4	9.0	-3%
	McClain Gas 1	55	R4	-4%	2046	55	R4	29.0	-9%	2046	55	R4	29.0	-3%
	McClain Gas 2	55	R4	-4%	2046	55	R4	28.8	-9%	2046	55	R4	28.8	-3%
Total Fuel Holders, Producers, and Accessories														
343.00	Prime Movers													
	Redbud 1	35	R2	-3%	2049	35	R2	24.2	-10%	2049	50	R3	30.2	-3%
	Redbud 2	35	R2	-4%	2049	35	R2	24.1	-10%	2049	50	R3	30.2	-3%
	Redbud 3	35	R2	-4%	2049	35	R2	24.4	-10%	2049	50	R3	30.3	-3%
	Redbud 4	35	R2	-4%	2049	35	R2	24.2	-10%	2049	50	R3	30.2	-3%
	Horseshoe Lake 9 and 10	35	R2	-1%	2035	35	R2	16.4	-4%	2035	50	R3	18.3	-1%
	Tinker	35	R2	-1%	2025	35	R2	8.6	-6%	2025	50	R3	8.9	-3%
	McClain Gas 1	35	R2	-4%	2046	35	R2	23.6	-9%	2046	50	R3	28.1	-3%
	McClain Gas 2	35	R2	-4%	2046	35	R2	22.8	-9%	2046	50	R3	27.8	-3%
	McClain Steam 1	35	R2	-4%	2046	35	R2	21.3	-8%	2046	50	R3	27.1	-3%
Total Prime Movers														
LTSA														
343.10	5-Year													
	Redbud 1	5	SQ	0%		5	SQ	2.5	0%		5	SQ	2.5	0%
	Redbud 2	5	SQ	0%		5	SQ	2.5	0%		5	SQ	2.5	0%
	Redbud 3	5	SQ	0%		5	SQ	2.5	0%		5	SQ	2.5	0%
	Redbud 4	5	SQ	0%		5	SQ	2.5	0%		5	SQ	2.5	0%
	McClain Gas 1	5	SQ	0%		5	SQ	2.5	0%		5	SQ	2.5	0%
	McClain Gas 2	5	SQ	0%		5	SQ	2.5	0%		5	SQ	2.5	0%
	20-Year													
	Redbud 1	20	SQ	0%		20	SQ	7.5	0%		20	SQ	7.5	0%
	Redbud 2	20	SQ	0%		20	SQ	7.5	0%		20	SQ	7.5	0%
	Redbud 3	20	SQ	0%		20	SQ	7.5	0%		20	SQ	7.5	0%
	Redbud 4	20	SQ	0%		20	SQ	7.5	0%		20	SQ	7.5	0%
Total LTSA														
Total Account 343														
344.00	Generators													
	Redbud 1	45	R2.5	-3%	2049	50	R2	29.8	-10%	2049	50	R2	29.8	-3%
	Redbud 3	45	R2.5	-4%	2049	50	R2	30.1	-10%	2049	50	R2	30.1	-3%
	Redbud 4	45	R2.5	-4%	2049	50	R2	30.1	-10%	2049	50	R2	30.1	-3%
	Horseshoe Lake 9 and 10	45	R2.5	-1%	2035	50	R2	17.8	-4%	2035	50	R2	17.8	-1%
	Tinker	45	R2.5	-1%	2025	50	R2	8.8	-6%	2025	50	R2	8.8	-3%
	Mustang Solar	30	S2.5	-5%	2040	30	S2.5	22.1	-4%	2040	30	S2.5	22.1	-2%
Total Generators														
344.00	Generators - Wind													
	Centennial Wind Farm	40	R3	-1%	2031	40	R2.5	14.3	-2%	2031	40	R2.5	14.3	-1%
	OU Spirit Wind Farm	40	R3	-1%	2034	40	R2.5	17.1	-2%	2034	40	R2.5	17.1	-1%
	Crossroads Wind Farm	40	R3	-1%	2037	40	R2.5	19.9	-3%	2037	40	R2.5	19.9	-1%
Total Generators - Wind														

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Account	Description	Current				OGE Proposed-Supplemental Testimony					AG Proposed			
		AYFR	Iowa	Future	Net Salvage	AYFR	Iowa	Avg	Future	AYFR	Iowa	Avg	Future	
			Proj Life	Curve Shape			Curve	Rem Life	Net Salvage		Proj Life	Curve Shape	Rem Life	Net Salvage
A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
345.00	Accessory Electric Equipment													
	Redbud 1	45	R2.5	-3%	2049	50	R2.5	29.2	-10%	2049	50	R2.5	29.2	-3%
	Redbud 2	45	R2.5	-4%	2049	50	R2.5	29.2	-10%	2049	50	R2.5	29.2	-3%
	Redbud 3	45	R2.5	-4%	2049	50	R2.5	29.1	-10%	2049	50	R2.5	29.1	-3%
	Redbud 4	45	R2.5	-4%	2049	50	R2.5	30.1	-10%	2049	50	R2.5	30.1	-3%
	Horseshoe Lake 9 and 10	45	R2.5	-1%	2035	50	R2.5	17.9	-4%	2035	50	R2.5	17.9	-1%
	Tinker	45	R2.5	-1%	2025	50	R2.5	8.7	-6%	2025	50	R2.5	8.7	-3%
	McClain Gas 1	45	R2.5	-4%	2046	50	R2.5	27.2	-9%	2046	50	R2.5	27.2	-3%
	McClain Gas 2	45	R2.5	-4%	2046	50	R2.5	27.0	-9%	2046	50	R2.5	27.0	-3%
	McClain Steam 1	45	R2.5	-4%	2046	50	R2.5	26.5	-8%	2046	50	R2.5	26.5	-3%
	Mustang Solar	45	S2.5	0%	2040	45	S2.5	23.2	-4%	2040	45	S2.5	23.2	-2%
	Total Accessory Electric Equipment													
345.00	Accessory Electric Equipment - Wind													
	Centennial Wind Farm	35	R3	-1%	2031	35	R3	14.6	-2%	2031	35	R3	14.6	-1%
	OU Spirit Wind Farm	35	R3	-1%	2034	35	R3	17.5	-2%	2034	35	R3	17.5	-1%
	Crossroads Wind Farm	35	R3	-1%	2037	35	R3	19.8	-3%	2037	35	R3	19.8	-1%
	Total Accessory Electric Equipment - Wind													
346.00	Miscellaneous Power Plant Equipment													
	Redbud 1	40	R2	-3%	2049	40	R2	27.2	-10%	2049	40	R2	27.2	-3%
	Redbud 2	40	R2	-4%	2049	40	R2	28.4	-10%	2049	40	R2	28.4	-3%
	Redbud 3	40	R2	-4%	2049	40	R2	28.7	-10%	2049	40	R2	28.7	-3%
	Redbud 4	40	R2	-4%	2049	40	R2	28.8	-10%	2049	40	R2	28.8	-3%
	Horseshoe Lake 9 and 10	40	R2	-1%	2035	40	R2	16.7	-4%	2035	40	R2	16.7	-1%
	Tinker	40	R2	-1%	2025	40	R2	8.6	-6%	2025	40	R2	8.6	-3%
	McClain Gas 1	40	R2	-4%	2046	40	R2	24.0	-9%	2046	40	R2	24.0	-3%
	Total Miscellaneous Power Plant Equipment													
346.00	Miscellaneous Power Plant Equipment - Wind													
	Centennial Wind Farm	35	R2.5	-1%	2031	35	R2.5	14.5	-2%	2031	35	R2.5	14.5	-1%
	OU Spirit Wind Farm	35	R2.5	-1%	2034	35	R2.5	17.3	-2%	2034	35	R2.5	17.3	-1%
	Crossroads Wind Farm	35	R2.5	-1%	2037	35	R2.5	20.0	-3%	2037	35	R2.5	20.0	-1%
	Total Miscellaneous Power Plant Equipment - Wind													
TOTAL OTHER PRODUCTION PLANT														
TRANSMISSION PLANT														
350.10	Land													
350.20	Land Rights	100	R4	0%		75	S4	61.7	0%		75	S4	61.7	0%
352.00	Structures and Improvements	65	R4	0%		65	S4	52.4	-5%		65	S4	52.4	-5%
	Station Equipment													
353.00	Station Equipment	63	R2	0%		57	R2	46.7	-30%		57	R2	46.7	-30%
353.10	Station Equipment - Step Up Transformers	45	R2	-10%		50	R1.5	38.3	-10%		50	R1.5	38.3	-10%
	Total Station Equipment													
354.00	Towers and Fixtures	75	R4	0%		75	R4	59.1	-25%		75	R4	59.1	-25%
355.00	Poles and Fixtures	65	S0.5	-15%		60	R1	54.0	-70%		60	R1	54.0	-65%
356.00	Overhead Conductors and Devices	65	R3	-50%		65	R2.5	54.3	-60%		65	R2.5	54.3	-35%
358.00	Underground Conductors and Devices	40	S2.5	-50%		45	S2.5	0.0	0%		45	S2.5	0.0	0%
TOTAL TRANSMISSION PLANT														
DISTRIBUTION PLANT														
360.10	Land													
360.20	Land Rights	99	L4	0%		70	S4	52.4	0%		70	S4	52.4	0%
361.00	Structures and Improvements	70	R2.5	0%		65	R2.5	54.4	-5%		65	R2.5	54.4	-5%
362.00	Station Equipment	68	R2.5	-10%		60	R2.5	46.6	-30%		60	R2.5	46.6	-30%
364.00	Poles, Towers, and Fixtures	55	R1	-30%		55	R1	44.3	-65%		55	R1	44.3	-45%
365.00	Overhead Conductors and Devices	54	R0.5	-60%		55	R0.5	45.1	-55%		55	R0.5	45.1	-40%
366.00	Underground Conduit	65	R2.5	-50%		60	R2	50.0	-20%		65	R2	55.7	-10%

Oklahoma Gas and Electric Company
 Table 5: Current and Proposed Parameters
 As of December 31, 2016

Account	Description A	Current				OGE Proposed-Supplemental Testimony					AG Proposed			
		AYFR B	Iowa Proj Life C	Future Curve Shape D	Net Salvage E	AYFR F	Iowa Proj Life G	Avg Curve Rem H	Future Net Salvage I	AYFR K	Iowa Proj Life L	Avg Curve Rem M	Future Net Salvage N	O
			Life	Shape	Salvage		Life	Rem	Salvage		Life	Rem	Salvage	
367.00	Underground Conductors and Devices	64	R2.5	-25%	62	R2.5	50.4	-30%	62	R2.5	50.4	-15%		
368.00	Line Transformers	44	O2	-25%	42	O1	32.7	-30%	42	O1	32.7	-30%		
369.00	Services	53	R5	-25%	55	R4	39.3	-20%	55	R4	39.3	-5%		
	Meters													
370.00	Meters - Smart Meters	15	S2.5	0%	15	S2.5	10.6	-10%	19	R3	14.8	-10%		
370.01	Meters - Metering Equipment	13	L0	-5%	13	L0	8.7	-10%	13	L0	8.7	-10%		
	Total Meters													
371.00	Installations on Customers' Premises	15	L3	0%	7	R4	4.6	0%	7	R4	4.6	0%		
373.00	Street Lighting and Signal Systems	31	L2	0%	27	L1	17.7	-40%	40	R0.5	33.1	-40%		
TOTAL DISTRIBUTION PLANT														
GENERAL PLANT														
389.10	Land													
389.20	Land Rights	54	R4	0%	50	R4	19.1	0%	50	R4	19.1	0%		
390.00	Structures and Improvements	40	R2.5	0%	40	R2.5	29.2	-5%	40	R2.5	29.2	-5%		
	Office Furniture and Equipment													
391.00	Office Furniture and Equipment	15	SQ	0%	15	SQ	9.6	0%	15	SQ	9.6	0%		
391.10	Computer Equipment	5	SQ	0%	5	SQ	4.2	0%	5	SQ	4.2	0%		
	Total Office Furniture and Equipment													
	Transportation Equipment													
392.10	Cars and Trucks	9.5	S2.5	0%	10	S2.5	5.3	10%	10	S2.5	5.3	10%		
392.50	Heavy Trucks	13	L2.5	20%	13	L2.5	7.7	10%	13	L2.5	7.7	10%		
392.60	Trailers	23	S0.5	15%	23	S0.5	18.1	10%	23	S0.5	18.1	10%		
	Total Transportation Equipment													
393.00	Stores Equipment	25	SQ	0%	25	SQ	17.1	0%	25	SQ	17.1	0%		
394.00	Tools, Shop, and Garage Equipment	25	SQ	0%	25	SQ	15.1	0%	25	SQ	15.1	0%		
395.00	Laboratory Equipment	20	SQ	0%	20	SQ	10.3	0%	20	SQ	10.3	0%		
396.00	Power Operated Equipment	18	L2	0%	18	L2	11.4	15%	18	L2	11.4	15%		
397.00	Communication Equipment	10	SQ	15%	10	SQ	5.5	0%	10	SQ	5.5	0%		
398.00	Miscellaneous Equipment	20	SQ	0%	20	SQ	11.2	0%	20	SQ	11.2	0%		
TOTAL GENERAL PLANT														
RESERVE ADJUSTMENT FOR AMORTIZATION														
391.00	Office Furniture and Equipment						5.0				5.0			
393.00	Stores Equipment						5.0				5.0			
394.00	Tools, Shop, and Garage Equipment						5.0				5.0			
395.00	Laboratory Equipment						5.0				5.0			
397.00	Communication Equipment						5.0				5.0			
398.00	Miscellaneous Equipment						5.0				5.0			
TOTAL RESERVE ADJUSTMENT FOR AMORTIZATION														
TOTAL DEPRECIABLE ELECTRIC PLANT														

Oklahoma Gas and Electric Company
 Table 6: Calculation of Weighted Net Salvage Percent for Generation Plant
 As of December 31, 2016

Location	Total Future Retirements		Terminal Retirements		Interim Retirements		Net Salvage		Estimated Net Salvage (%)
	(1)	(2)	(3)=(2)/(1)	(4)	(5)	(6)=(5)/(1)	(7)	(8)=(2)+(5)	
Steam Production									
Horseshoe Lake 6	(46,389,470)	(43,642,011)	94.08%	-7%	(2,747,459)	5.92%	-21%	(46,389,470)	-8%
Horseshoe Lake 7	(36,649,398)	(31,069,738)	84.78%	-7%	(5,579,660)	15.22%	-21%	(36,649,398)	-9%
Horseshoe Lake 8	(46,697,049)	(38,155,784)	81.71%	-7%	(8,541,264)	18.29%	-21%	(46,697,049)	-10%
Mustang 3	(18,821,382)	(18,821,382)	100.00%	-10%		0.00%	-21%	(18,821,382)	-10%
Mustang 4	(48,991,723)	(48,991,723)	100.00%	-10%		0.00%	-21%	(48,991,723)	-10%
Seminole 1	(108,333,295)	(92,198,126)	85.11%	-8%	(16,135,169)	14.89%	-21%	(108,333,295)	-10%
Seminole 2	(78,187,898)	(62,176,933)	79.52%	-8%	(16,010,965)	20.48%	-21%	(78,187,898)	-11%
Seminole 3	(91,190,455)	(74,137,443)	81.30%	-8%	(17,053,012)	18.70%	-21%	(91,190,455)	-10%
Muskogee 4	(306,310,015)	(257,875,684)	84.19%	-4%	(48,434,331)	15.81%	-21%	(306,310,015)	-7%
Muskogee 5	(197,825,189)	(159,289,599)	80.52%	-4%	(38,535,590)	19.48%	-21%	(197,825,189)	-7%
Muskogee 6	(441,315,161)	(338,539,737)	76.71%	-4%	(102,775,424)	23.29%	-21%	(441,315,161)	-8%
Sooner 1	(390,380,099)	(322,505,795)	82.61%	-4%	(67,874,304)	17.39%	-21%	(390,380,099)	-7%
Sooner 2	(227,497,199)	(179,061,675)	78.71%	-4%	(48,435,523)	21.29%	-21%	(227,497,199)	-8%
Total Steam Production	(2,038,588,331)	(1,666,465,630)			(372,122,701)			(2,038,588,331)	
Other Production Plant									
Redbud 1	(147,889,651)	(112,165,373)	75.84%	-3%	(35,724,278)	24.16%	-4%	(147,889,651)	-3%
Redbud 2	(76,233,679)	(55,735,809)	73.11%	-3%	(20,497,870)	26.89%	-4%	(76,233,679)	-3%
Redbud 3	(75,962,557)	(55,918,648)	73.61%	-3%	(20,043,909)	26.39%	-4%	(75,962,557)	-3%
Redbud 4	(70,768,150)	(52,278,068)	73.87%	-3%	(18,490,082)	26.13%	-4%	(70,768,150)	-3%
Horseshoe Lake 9 & 10	(46,372,133)	(39,946,845)	86.14%	-1%	(6,425,288)	13.86%	-4%	(46,372,133)	-1%
Tinker	(11,395,007)	(10,897,894)	95.64%	-3%	(497,113)	4.36%	-4%	(11,395,007)	-3%
McClain Gas 1	(98,236,261)	(77,872,897)	79.27%	-3%	(20,363,364)	20.73%	-4%	(98,236,261)	-3%
McClain Gas 2	(77,725,653)	(60,011,594)	77.21%	-3%	(17,714,059)	22.79%	-4%	(77,725,653)	-3%
McClain Steam 1	(35,431,495)	(25,652,598)	72.40%	-3%	(9,778,897)	27.60%	-4%	(35,431,495)	-3%
Total Other Production	(640,014,587)	(490,479,727)			(149,534,860)			(640,014,587)	
Wind Production									
Centennial	(249,929,539)	(217,707,456)	87.11%	0%	(32,222,082)	12.89%	-5%	(249,929,539)	-1%
OU Spirit	(191,114,593)	(144,522,755)	75.62%	0%	(46,591,838)	24.38%	-5%	(191,114,593)	-1%
Crossroads	(414,939,210)	(333,832,782)	80.45%	0%	(81,106,428)	19.55%	-5%	(414,939,210)	-1%
Total Wind Production	(855,983,342)	(696,062,994)			(159,920,348)			(855,983,342)	
Solar Production									
Mustang Solar	(6,771,150)	(5,414,679)	79.97%	-1%	(1,356,471)	20.03%	-4%	(6,771,150)	-2%
Total Solar Production	(6,771,150)	(5,414,679)			(1,356,471)			(6,771,150)	

Oklahoma Gas and Electric Company
 Table 7: Calculation of Terminal Net Salvage Percent
 As of December 31, 2016

Plant	Study		Decommissioning		Estimated		5%		Estimated		Terminal		Percent
	Estimated Decommissioning Cost	Decommissioning Asbestos Removal	Cost Without Asbestos Removal	Asbestos Value	Scrap Value	Estimated Project Indirects	Estimated Project Contingency	Estimated Cost (2017 \$)	Estimated Cost (2017 \$)	Estimated Retirement	Estimated Retirement		
A	B	C	D=B-C	E	F	G	H=SUM(D-G)	I=SUM(D-G)	J=SUM(D-G)	K=SUM(D-G)	L=SUM(D-G)	M=SUM(D-G)	
Steam Production													
Horseshoe Lake 6	4,410,632	399,000	4,011,632	(2,350,660)	200,582	0	1,861,554	(43,642,011)					
Horseshoe Lake 7	5,138,771	515,000	4,623,771	(2,514,069)	231,189	0	2,340,891	(31,069,738)					
Horseshoe Lake 8	8,437,396	1,180,000	7,257,396	(4,202,971)	362,870	0	3,417,295	(38,155,784)					
Subtotal Horseshoe	17,986,800	2,094,000	15,892,800	(9,067,700)	794,640	0	7,619,740	(112,867,533)					-7%
Mustang 3	6,419,790	1,430,000	4,989,790	(2,423,166)	249,490	0	2,816,114	(18,821,382)					
Mustang 4	9,845,210	2,720,000	7,125,210	(3,616,834)	356,260	0	3,864,636	(48,991,723)					
Subtotal Mustang	16,265,000	4,150,000	12,115,000	(6,040,000)	605,750	0	6,680,750	(67,813,109)					-10%
Seminole 1	11,076,852	1,451,000	9,625,852	(4,319,902)	481,293	0	5,787,242	(92,198,126)					
Seminole 2	11,063,140	1,451,000	9,612,140	(4,307,501)	480,607	0	5,785,246	(62,176,933)					
Seminole 3	11,791,008	1,451,000	10,340,008	(4,279,597)	517,000	0	6,577,412	(74,137,443)					
Subtotal Seminole	33,931,000	4,353,000	29,578,000	(12,907,000)	1,478,900	0	18,149,900	(228,512,502)					-8%
Muskogee 4	12,409,131	1,013,000	11,396,131	(6,341,350)	569,807	0	5,624,588	(257,875,684)					
Muskogee 5	12,411,208	1,013,000	11,398,208	(6,341,350)	569,910	0	5,626,768	(159,289,599)					
Muskogee 6	23,634,661	1,013,000	22,621,661	(6,474,301)	1,131,083	0	17,278,443	(338,539,737)					
Subtotal Muskogee	48,455,000	3,039,000	45,416,000	(19,157,000)	2,270,800	0	28,529,800	(755,705,020)					-4%
Sooner 1	14,462,456	2,258,000	12,204,456	(7,955,887)	610,223	0	4,858,792	(322,505,795)					
Sooner 2	25,752,544	2,258,000	23,494,544	(9,392,113)	1,174,727	0	15,277,158	(179,061,675)					
Subtotal Sooner	40,215,000	4,516,000	35,699,000	(17,348,000)	1,784,950	0	20,135,950	(501,567,471)					-4%
Total Steam Production	156,852,800	18,152,000	138,700,800	(64,519,700)	6,995,040	0	81,116,140	(1,666,465,630)					
Other Production Plant													
Redbud 1	3,737,791		3,737,791	(2,074,250)	187,000	0	1,850,541	(112,165,373)					
Redbud 2	3,738,955		3,738,955	(2,074,250)	187,000	0	1,851,705	(55,735,809)					
Redbud 3	3,736,627		3,736,627	(2,074,250)	187,000	0	1,849,377	(55,918,648)					
Redbud 4	3,736,627		3,736,627	(2,074,250)	187,000	0	1,849,377	(52,278,068)					
Subtotal Redbud	14,950,000	0	14,950,000	(8,297,000)	748,000	0	7,401,000	(276,097,899)					-3%
Horseshoe Lake 9 & 10	1,273,200		1,273,200	(771,300)	63,660	0	565,560	(39,946,845)					-1%
Tinker	789,000		789,000	(513,000)	39,000	0	315,000	(10,897,894)					-3%
McClain CC 1	7,149,000		7,149,000	(3,295,000)	357,000	0	4,211,000	(163,537,089)					-3%
Total Other Production	24,161,200	0	24,161,200	(12,876,300)	1,207,660	0	12,492,560	(490,479,727)					
Wind Production*													
Centennial	6,655,000		6,655,000	(6,049,000)	333,000	0	939,000	(217,707,456)					0%
Ou Spirit	4,116,000		4,116,000	(4,170,000)	206,000	0	152,000	(144,522,755)					0%
Crossroads	9,167,000		9,167,000	(9,141,000)	458,000	0	484,000	(333,832,782)					0%
Total Wind Production	19,938,000	0	19,938,000	(19,360,000)	997,000	0	1,575,000	(696,062,994)					
Solar Production													
Mustang Solar	226,000		226,000	(161,000)	11,000	0	76,000	(5,414,679)					-1%
Total Solar Production	226,000	0	226,000	(161,000)	11,000	0	76,000	(5,414,679)					

* Wind Production Terminal Net Salvage set to 0% since it is a legal retirement obligation and included in ARO

Attorney General of Oklahoma
Data Request AG-6
Cause No. PUD 201700496

- 6-1 Please refer to the Direct Testimony of Jeffrey T. Kopp, Direct Exhibit JTK-1, pages 4-3, 4-4, and 4-5, paragraphs 11, 16, 26, 27, and 33, which discuss various kinds of environmental remediation that may occur as part of plant decommissioning.**
- a) Do the amounts in the Decommissioning Studies in Exhibit JTK-1 include the costs to remove and/or remediate asbestos?**
 - b) Is removing and/or remediate asbestos included in or covered by any asset retirement obligations (“AROs”) for any unit covered by the Decommissioning Studies?**
 - c) Is the closure of any pond or lagoon included in or covered by any AROs for any unit covered by the Decommissioning Studies in Exhibit JTK-1?**
 - d) Are any other costs included in the Decommissioning Studies in Exhibit JTK-1 costs that are included in or subject to AROs? If so, please identify each one.**
 - e) Is any coal pile remediation covered by any AROs for any unit covered by the Decommissioning Studies in Exhibit JTK-1?**
 - f) If any costs included in the Decommissioning Studies in Exhibit JTK-1 are costs that are also subject to AROs, please explain why these costs should not be excluded from the Decommissioning Studies in Exhibit JTK-1.**

Response*:

- a. Yes. Costs for asbestos remediation are broken out as separate line items in the tables provided in Appendix B of Exhibit JTK-1.
- b. Yes. See attachment **AG 6-1_Att** for list of ARO's related to asbestos.
- c. No. There is one ARO for closure of the ash pond at Muskogee. Please see attachment **AG 6-1_Att** for details of this ARO. On pages 4-6, Section r.2.5 - Muskogee Power Plant of the Decommissioning Study, it states "The on-site ash pond has already been closed and is excluded from the decommissioning costs presented in this study."
- d. No.
- e. There are no AROs for coal pile remediation.
- f. The cost of Asset Retirement Obligations should not be excluded from the Decommissioning Study in Exhibit JTK-1. OG&E's accrued removal recovery has never included final decommissioning. While we have reclassified amounts of regular removal to an ARO, we have not recovered any final decommissioning costs including asbestos remediation.

Response provided by: Jeffrey Kopp
Response provided on: February 15, 2018
Contact & Phone No: Jason Bailey 405-556-3406

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

OG&E DATA REQUEST AG 6-1 Attachment AG 6-1b Cause No. PUD 201700496		
PLANT	Type of ARO	ARO Liability
Sooner Power Plant	Asbestos Remediation	\$ 279,819.88
Horseshoe Lake Power Plant	Asbestos Remediation	\$ 5,438,847.67
Muskogee Coal Power Plant	Asbestos Remediation	\$ 376,459.75
Seminole Power Plant	Asbestos Remediation	\$ 2,391,092.40
Mustang Power Plant	Asbestos Remediation	\$ 6,135,476.05
Muskogee Unit 4	Ash Pond Remediation	\$ 2,684,653.60
		14,621,695.81

Attorney General of Oklahoma
Data Request AG-21
Cause No. PUD 201700496

21-5 Please refer to the Company's response to AG-OGE-6-1, including the Attachment AG 6-1b. The attachment shows an ARO liability of \$6,135,476 for the Mustang Power Plant for Asbestos Remediation. Please provide all documents and workpapers used to determine the ARO liability of \$6,135,476 for the Mustang Power Plant for Asbestos Remediation. Please specifically include any documents what asbestos was included in the remediation amount and any documents identifying what, if any, asbestos at the Mustang production plant was excluded in the determination of the remediation amount, along with the reasons for such an exclusion.

Response*:

See **AG 21-5_Att** to see the vendor estimate that was used in the calculation of the Mustang 1-4 ARO for asbestos removal. The total asbestos removal estimate as of 2015 was \$5,658,000 when the ARO was created. This estimate included the removal of all asbestos at the Plant. Based on the accounting standards required from implementation of SFAS 143 and FIN 47, in 2015 the liability began accreting monthly and as of 12/31/2017 the liability balance was \$6,135,476 as shown in **AG 6-1_Att**.

Response provided by:	<u>Carla Chupik</u>
Response provided on:	<u>April 17, 2018</u>
Contact & Phone No:	<u>Jason Bailey 405-553-3406</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Environmental Action Inc.

October 5, 2015

Attn.: Matt Grimes
OG&E

RE: Mustang Plant Units 1, 2, 3, & 4

Environmental Action, Inc. is pleased to provide this budgetary estimate for asbestos abatement on the above referenced project. The work will be performed in accordance with all local, state, and federal regulations.

Scope:

- Erect scaffolding and enclosures necessary to perform the asbestos abatement located on the four units at the Mustang Plant. Perform asbestos abatement utilizing ODOL demolition procedures. The building will be completely vacant with all power being locked out and tagged by others prior to EAI mobilizing. Temporary electric will be provided by OG&E as needed to perform the abatement project. The cutting of the boiler casings necessary to access the ACM will be performed by others at no cost to EAI.

Total price not to exceed - \$5,658,000.00

The price quoted includes the following:

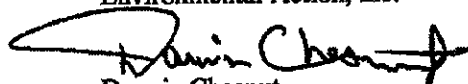
- Regulatory notifications and fees
- All labor, materials, and equipment
- Disposal of ACM in an EPA approved landfill
- Our standard insurance coverage's
- Independent third party air monitoring
- OG&E providing active elevators for the duration of the abatement project
- Scaffolding necessary for access to abate the asbestos insulation
- 40 hour work weeks

Price excludes:

- Premium time
- Cutting of welded boiler casing

We anticipate a two year completion on the project. Please feel free to call should you have any questions or need additional information. We appreciate the opportunity to be of service.

Respectfully submitted,
Environmental Action, Inc.



Darwin Chesnut
Oklahoma City Operations Manager
(405) 990-0070

Fleet Decommissioning Cost Estimate Study

prepared for

**Oklahoma Gas & Electric
Fleet Decommissioning Cost Estimate Study
Oklahoma City, Oklahoma**

Project No. 95525

5/22/2017

prepared by

**Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri**

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**Table B-6
 Mustang ST
 Decommissioning Cost Summary**

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Scrap Value
Mustang ST						
<i>Unit 1</i>						
Asbestos Removal	\$ -	\$ -	\$ -	\$ 537,000	\$ 537,000	\$ -
Boiler	\$ 599,000	\$ 865,000	\$ -	\$ -	\$ 1,255,000	\$ -
Steam Turbine & Building	\$ 390,000	\$ 440,000	\$ -	\$ -	\$ 829,000	\$ -
Switchgear and Electrical	\$ 10,000	\$ 11,000	\$ -	\$ -	\$ 21,000	\$ -
Stacks	\$ 90,000	\$ 101,000	\$ -	\$ -	\$ 191,000	\$ -
Cooling Towers & Circulating Water	\$ 55,000	\$ 62,000	\$ -	\$ 12,000	\$ 129,000	\$ -
On-site Concrete Crushing & Disposal	\$ -	\$ -	\$ 56,000	\$ -	\$ 56,000	\$ -
Debris	\$ -	\$ -	\$ 101,000	\$ -	\$ 101,000	\$ -
Scrap	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1,104,000)
Subtotal	\$ 1,134,000	\$ 1,279,000	\$ 157,000	\$ 549,000	\$ 3,118,000	\$ (1,104,000)
<i>Unit 2</i>						
Asbestos Removal	\$ -	\$ -	\$ -	\$ 537,000	\$ 537,000	\$ -
Boiler	\$ 599,000	\$ 665,000	\$ -	\$ -	\$ 1,255,000	\$ -
Steam Turbine & Building	\$ 390,000	\$ 440,000	\$ -	\$ -	\$ 829,000	\$ -
Switchgear and Electrical	\$ 10,000	\$ 11,000	\$ -	\$ -	\$ 21,000	\$ -
Stacks	\$ 90,000	\$ 101,000	\$ -	\$ -	\$ 191,000	\$ -
Cooling Towers & Circulating Water	\$ 55,000	\$ 62,000	\$ -	\$ 11,000	\$ 127,000	\$ -
On-site Concrete Crushing & Disposal	\$ -	\$ -	\$ 56,000	\$ -	\$ 56,000	\$ -
Debris	\$ -	\$ -	\$ 101,000	\$ -	\$ 101,000	\$ -
Scrap	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1,104,000)
Subtotal	\$ 1,135,000	\$ 1,280,000	\$ 157,000	\$ 548,000	\$ 3,118,000	\$ (1,104,000)
<i>Unit 3</i>						
Asbestos Removal	\$ -	\$ -	\$ -	\$ 1,430,000	\$ 1,430,000	\$ -
Boiler	\$ 1,332,000	\$ 1,302,000	\$ -	\$ -	\$ 2,624,000	\$ -
Steam Turbine & Building	\$ 700,000	\$ 790,000	\$ -	\$ -	\$ 1,491,000	\$ -
Switchgear and Electrical	\$ 10,000	\$ 11,000	\$ -	\$ -	\$ 21,000	\$ -
Cooling Towers & Circulating Water	\$ 77,000	\$ 86,000	\$ -	\$ 9,000	\$ 172,000	\$ -
GSU & Foundation	\$ 26,000	\$ 29,000	\$ -	\$ -	\$ 55,000	\$ -
On-site Concrete Crushing & Disposal	\$ -	\$ -	\$ 52,000	\$ -	\$ 52,000	\$ -
Debris	\$ -	\$ -	\$ 23,000	\$ -	\$ 23,000	\$ -
Scrap	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (2,387,000)
Subtotal	\$ 2,045,000	\$ 2,308,000	\$ 75,000	\$ 1,439,000	\$ 5,868,000	\$ (2,367,000)
<i>Unit 4</i>						
Asbestos Removal	\$ -	\$ -	\$ -	\$ 2,720,000	\$ 2,720,000	\$ -
Boiler	\$ 1,860,000	\$ 2,123,000	\$ -	\$ -	\$ 4,004,000	\$ -
Steam Turbine & Building	\$ 831,000	\$ 939,000	\$ -	\$ -	\$ 1,770,000	\$ -
Switchgear and Electrical	\$ 10,000	\$ 11,000	\$ -	\$ -	\$ 21,000	\$ -
Cooling Towers & Circulating Water	\$ 130,000	\$ 147,000	\$ -	\$ 40,000	\$ 317,000	\$ -
GSU & Foundation	\$ 29,000	\$ 32,000	\$ -	\$ -	\$ 61,000	\$ -
On-site Concrete Crushing & Disposal	\$ -	\$ -	\$ 63,000	\$ -	\$ 63,000	\$ -
Debris	\$ -	\$ -	\$ 43,000	\$ -	\$ 43,000	\$ -
Scrap	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (3,532,000)
Subtotal	\$ 2,880,000	\$ 3,252,000	\$ 106,000	\$ 2,760,000	\$ 8,999,000	\$ (3,533,000)
<i>Common</i>						
All BOP Buildings	\$ 209,000	\$ 226,000	\$ -	\$ -	\$ 445,000	\$ -
All Other Tanks	\$ 26,000	\$ 30,000	\$ -	\$ -	\$ 56,000	\$ -
Transformer Oil Disposal	\$ -	\$ -	\$ -	\$ 36,000	\$ 36,000	\$ -
Mercury & Universal Waste Disposal	\$ -	\$ -	\$ -	\$ 29,000	\$ 29,000	\$ -
Pond Closures	\$ -	\$ -	\$ -	\$ 267,000	\$ 267,000	\$ -
Concrete Removal, Crushing, & Disposal	\$ -	\$ -	\$ 20,000	\$ -	\$ 20,000	\$ -
Scrap	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (140,000)
Subtotal	\$ 346,000	\$ 391,000	\$ 20,000	\$ 636,000	\$ 1,398,000	\$ (140,000)
Subtotal	\$ 5,271,000	\$ 5,951,000	\$ 208,000	\$ 4,838,000	\$ 22,501,000	\$ (8,248,000)
TOTAL DECOM COST (CREDIT)					\$ 22,501,000	\$ (8,248,000)
PROJECT INDIRECTS (5%)					\$ 1,125,000	
CONTINGENCY (20%)					\$ 4,500,000	
TOTAL PROJECT COST (CREDIT)					\$ 28,126,000	\$ (8,248,000)
TOTAL NET PROJECT COST (CREDIT)					\$ 19,878,000	

Attorney General of Oklahoma
Data Request AG-21
Cause No. PUD 201700496

21-2 Please refer to page 204 of the OGE FERC Form 1 for the year 2016, which shows \$43,620,335 as the asset retirement cost for Other Production. Please provide a breakdown showing the dollar amount of each of the AROs that are included in this amount. For each ARO, please include the name of the associated production plant and a clearly understandable description of the purpose of the ARO—for example, asbestos remediation at the Sooner Power Plant.

Response*:

Other Production		
Centennial Wind Turbines	15,226,139.03	Removal of Windfarm Structures upon termination of the land lease
OU Spirit Wind Turbine	8,710,081.23	Removal of Windfarm Structures upon termination of the land lease
Crossroads Wind Turbines	19,684,115.87	Removal of Windfarm Structures upon termination of the land lease
	43,620,336.12	

Response provided by: Carla Chupik
Response provided on: April 17, 2018
Contact & Phone No: Jason Bailey 405-553-3406

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.



2016 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO ELECTRIC PLANT
AS OF DECEMBER 31, 2016

Prepared by:



Gannett Fleming

Excellence Delivered As Promised

OKLAHOMA GAS AND ELECTRIC COMPANY

ACCOUNT 364 POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		GROSS SALVAGE		NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
1991	946,267	411,214	43	138,760	15	272,454-	29-
1992	2,156,070	1,385,900	64	682,910	32	702,990-	33-
1993	2,315,989	1,588,199	69	741,715	32	846,484-	37-
1994	1,956,519	1,213,949	62	209,205	11	1,004,744-	51-
1995	2,125,050	1,466,148	69	309,232	15	1,156,916-	54-
1996	1,596,961	375,293	24	361,708	23	13,585-	1-
1997	1,075,671	834,582	78	1,122,766	104	288,184	27
1998	806,164	488,261	61	1,571,951	195	1,083,690	134
1999	1,152,200	880,718	76	508,119	44	372,598-	32-
2000	1,847,854	586,419	32	394,983	21	191,436-	10-
2001	1,317,967	1,333,639	101	433,028	33	900,611-	68-
2002	3,839,897	3,276,095	85	908,337	24	2,367,758-	62-
2003	2,231,433	1,776,249	80	613,779	28	1,162,470-	52-
2004	2,604,783	2,230,116	86	605,902	23	1,624,213-	62-
2005	3,184,082	2,157,546	68	466,512	15	1,691,035-	53-
2006	3,716,298	3,326,662	90	892,914	24	2,433,748-	65-
2007	2,497,297	3,713,094	149	3,843,351	154	130,257	5
2008	3,403,343	4,815,931	142	721,945	21	4,093,985-	120-
2009	2,985,131	3,931,571	132	905,996	30	3,025,575-	101-
2010	3,393,766	4,059,213	120	925,252	27	3,133,961-	92-
2011	3,908,694	4,219,885	108	887,857	23	3,332,028-	85-
2012	3,229,999	4,463,263	138	784,237	24	3,679,026-	114-
2013	3,686,199	4,462,924	121	760,184	21	3,702,740-	100-
2014	4,926,088	2,925,858	59	572,939	12	2,352,919-	48-
2015	3,333,448	4,920,089	148	819,983	25	4,100,106-	123-
2016	3,508,903	3,723,475	106	602,889	17	3,120,586-	89-
TOTAL	67,746,072	64,566,292	95	20,786,457	31	43,779,835-	65-

THREE-YEAR MOVING AVERAGES

91-93	1,806,109	1,128,438	62	521,128	29	607,309-	34-
92-94	2,142,859	1,396,016	65	544,610	25	851,406-	40-
93-95	2,132,519	1,422,765	67	420,051	20	1,002,715-	47-
94-96	1,892,843	1,018,463	54	293,382	15	725,082-	38-
95-97	1,599,227	892,008	56	597,902	37	294,106-	18-
96-98	1,159,599	566,046	49	1,018,809	88	452,763	39
97-99	1,011,345	734,520	73	1,067,612	106	333,092	33
98-00	1,268,739	651,799	51	825,018	65	173,219	14
99-01	1,439,340	933,592	65	445,377	31	488,215-	34-
00-02	2,335,239	1,732,051	74	578,783	25	1,153,268-	49-
01-03	2,463,099	2,128,661	86	651,715	26	1,476,946-	60-
02-04	2,892,037	2,427,487	84	709,339	25	1,718,147-	59-

OKLAHOMA GAS AND ELECTRIC COMPANY

ACCOUNT 364 POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
03-05	2,673,432	2,054,637	77	562,064	21	1,492,573-	56-
04-06	3,168,388	2,571,441	81	655,109	21	1,916,332-	60-
05-07	3,132,559	3,065,768	98	1,734,259	55	1,331,508-	43-
06-08	3,205,646	3,951,896	123	1,819,404	57	2,132,492-	67-
07-09	2,961,924	4,153,532	140	1,823,764	62	2,329,768-	79-
08-10	3,260,747	4,268,905	131	851,064	26	3,417,840-	105-
09-11	3,429,197	4,070,223	119	906,368	26	3,163,854-	92-
10-12	3,510,820	4,247,453	121	865,782	25	3,381,672-	96-
11-13	3,608,297	4,382,024	121	810,759	22	3,571,264-	99-
12-14	3,947,429	3,950,682	100	705,787	18	3,244,895-	82-
13-15	3,981,912	4,102,957	103	717,702	18	3,385,255-	85-
14-16	3,922,813	3,856,474	98	665,270	17	3,191,204-	81-
FIVE-YEAR AVERAGE							
12-16	3,736,927	4,099,122	110	708,046	19	3,391,075-	91-

Attorney General
Data Request AG-3
Cause No. PUD 201700496

3-7 Please refer to Part VIII the 2016 Depreciation Study, which includes Net Salvage Statistics by account.

a) Were there any amounts that were booked and then excluded from the Net Salvage Statistics data shown in Part VIII of the 2016 Depreciation Study?

b) Were any amounts included in the amounts in the Net Salvage Statistics data shown in Part VIII of the 2016 Depreciation Study not booked amounts?

c) If the response to either (a) or (b) is yes, provide the booked amounts, reconcile the difference between the booked amounts and the amounts shown in Part VIII of the 2016 Depreciation Study, and explain the reason for the adjustment or discrepancy.

Response*:

a. There were retirements and associated cost of removal and gross salvage that were booked but excluded from the Net Salvage Statistics data shown in Part VIII of the 2016 Depreciation Study.

b. There were no amounts included in the Net Salvage Statistics data shown in Part VIII of the 2016 Depreciation Study which were not booked.

c. The attached file, **AG-3-7_Att**, sets forth entries that were booked, but not included, in the Part VIII analyses. These entries were either final retirements for generation accounts, so they should be excluded in the interim net salvage analyses, or were abnormal transactions which should not be included in the determination of a net salvage percentage for all assets in the account.

Response provided by:	<u>John Spanos</u>
Response provided on:	<u>February 5, 2018</u>
Contact & Phone No:	<u>Jason Bailey 405-553-3406</u>

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Attorney General of Oklahoma
Data Request AG-11
Cause No. PUD 201700496

11-2 Please refer to OGE's response to AG-OGE-3-7, including OGE's attachment, along with the direct testimony of John J. Spanos, Direct Exhibit JJS-2, pages VIII-29 and VIII-30. Is it correct that OGE shows in Account 35300, in the year 2008, that the amount of \$893,474.70 was excluded from the Gross Salvage amount that was shown on pages VIII-29 and VIII-30 of Direct Exhibit JJS-2 (the Summary of Book Salvage in the depreciation study)? If this is not a correct statement, please provide the corrected statement and the support for that corrected statement.

Response*: It is correct that within attachment AG 3-7_Att in response to AG 3-7, there is an amount \$893,474.70 which was not included on pages VIII-29 and VIII-30 of Exhibit JJS-2. This entry was a reimbursement that was not considered a normal or recurring transaction, therefore, informed judgment in determining a future net salvage estimate for all existing assets should not be focused on this estimate. The future net salvage estimate should not be determined on statistical analyses alone of historical data.

Response provided by:	<u>John Spanos</u>
Response provided on:	<u>March 21, 2018</u>
Contact & Phone No:	<u>Jason Bailey 405-553-3406</u>

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Attorney General of Oklahoma
Data Request AG-11
Cause No. PUD 201700496

11-3 Please refer to OGE's response to AG-OGE-3-7, including OGE's attachment, along with the direct testimony of John J. Spanos, Direct Exhibit JJS-2, pages VIII-29 and VIII-30. Is it correct that OGE shows, in the year 2008, that no Cost of Removal recorded in Account 35300 was excluded from the Cost of Removal shown on pages VIII-29 and VIII-30 of Direct Exhibit JJS-2? If this is not a correct statement, please provide the corrected statement and the support for that corrected statement.

Response*: It must first be stated that cost of removal and gross salvage are not always time-synchronized as each component and the associated retirement could be recorded at different times. With that qualifying statement, there was no cost of removal associated with the reimbursement of \$893,474.70.

Response provided by:	<u>John Spanos</u>
Response provided on:	<u>March 21, 2018</u>
Contact & Phone No:	<u>Jason Bailey</u> <u>405-553-3406</u>

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Attorney General of Oklahoma
Data Request AG-11
Cause No. PUD 201700496

11-5 Please refer to “OGE2016-Service Life Data.xlsx” from the materials provided by John J. Spanos in response to AG-OGE-1-3, along with the direct testimony of John J. Spanos, Direct Exhibit JJS-2, pages VII-56 and VII-57. Is it correct that the file shows that, for the year 2008, no retirement amount recorded in Account 35300 was excluded from the Retirements During Age Interval amount that is shown on pages VII-57 and VII-57 of Direct Exhibit JJS-2 (the Original Life Table in the depreciation study)? If this is not a correct statement, please provide the corrected statement and the support for that corrected statement.

Response*: It is correct that in 2008 there were no retirements excluded from the life table as set forth on page VII-56 and VII-57 of Exhibit JJS-2.

Response provided by:	<u>John Spanos</u>
Response provided on:	<u>March 21, 2018</u>
Contact & Phone No:	<u>Jason Bailey</u> <u>405-553-3406</u>

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Attorney General of Oklahoma
Data Request AG-11
Cause No. PUD 201700496

11-8 Please refer to OGE's response to AG-OGE-11-7. Is it correct that the Cost of Removal provided in response to part (f) of AG-OGE-11-7 was excluded from the Cost of Removal shown in the direct testimony of John J. Spanos, Direct Exhibit JJS-2, section VIII? If this is not a correct statement, please provide the corrected statement and the support for that corrected statement.

Response*: There was no cost of removal associated with the reimbursement provided in response to AG 11-7. However, the reimbursement (gross salvage) was not excluded from gross salvage recorded in the Company accounting records. This reimbursement was excluded in the presentation in Part VIII of John J. Spanos Direct Exhibit JJS-2. Part VIII of Exhibit JJS-2 is the statistical presentation of regular retirements and the associated cost of removal and gross salvage considered to be a component of analyzing the net salvage percentage for the asset class. All recorded amounts are included in the accumulated depreciation for OG&E.

Response provided by:	<u>John Spanos</u>
Response provided on:	<u>March 21, 2018</u>
Contact & Phone No:	<u>Jason Bailey 405-553-3406</u>

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Attorney General of Oklahoma
Data Request AG-11
Cause No. PUD 201700496

11-12 Please refer to OGE's response to AG-OGE-3-7, including OGE's attachment, along with OGE's responses to AG-OGE-11-7, 11-8, and 11-9. Please provide the same information as in the AG-OGE-11-7, 11-8, and 11-9 responses for the \$1,229,974 reimbursement (which was excluded from Gross Salvage) for Account 364.00 in the year 2015, shown in the attachment to OGE's response to AG-OGE-3-7.

Response*: The \$1,229,974 gross salvage was a reimbursement in 2015 for Account 364 related to a few highway relocations of distribution lines. There was no identified cost of removal specific to these relocations. The amount was not excluded from the Company records, however, it was excluded from the presentation in Part VIII of John J. Spanos Direct Exhibit JJS-2. The amount was recorded in Account 108, Accumulated Provision for Depreciation.

Response provided by:	<u>John Spanos</u>
Response provided on:	<u>March 21, 2018</u>
Contact & Phone No:	<u>Jason Bailey 405-553-3406</u>

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Attorney General of Oklahoma
Data Request AG-13
Cause No. PUD 201700496

13-6 Please refer to OGE’s response to AG-OGE-3-7, including the attachment. In the attachment, the word “reimbursement” appears on several lines under the Comment column. On those lines marked “reimbursement” in which there is also an adjustment amount in the “Salvage Final” column, is it correct that some of the reimbursement amounts listed are reimbursements that were received by OGE as payments from an entity that had damaged or destroyed OGE’s property and/or from an insurance company on behalf of an entity that had damaged or destroyed OGE’s property? If this is not correct statement, please provide the corrected statement and the support for the corrected statement.

Response*: There are a few entries with the word “reimbursements” in the comment column that reflect payments received by OG&E related to damaged or destroyed OG&E property.

Response provided by:	<u>John Spanos</u>
Response provided on:	<u>March 22, 2018</u>
Contact & Phone No:	<u>Jason Bailey 405-553-3406</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Attorney General of Oklahoma
Data Request AG-22
Cause No. PUD 201700496

22-6 During the March 27, 2018, inspection trip, personnel from the Attorney General observed a project on Morgan Road in which OGE was removing an existing aerial line (poles, conductors, etc.) and building a new replacement aerial line further from the road. It was stated that OGE was doing this at the request of a government agency because the existing aerial line was in the way of a government project to widen the road.

a) Please provide the contract or agreement between OGE and the government agency pertaining to this project.

b) What does OGE expect the total dollar cost of the project to relocating these OGE facilities to be? Please provide all documents that support OGE's calculation.

c) What is the total dollar amount that the government agency has agreed to pay, or is reasonably expected to pay, to OGE for OGE relocating these OGE facilities? Please provide all documents that support OGE's expectation.

d) Was the existing aerial line (poles and other equipment now being removed) built on the then-existing road right-of-way when that existing aerial line was originally built?

e) Is it correct that if an existing OGE aerial line when it was originally constructed was built in the then-existing road right-of-way, the government agency will pay little or none of the cost of relocating that OGE aerial line, if that existing OGE aerial line must be relocated to clear the way for a government project? If this is not a correct statement, please provide the corrected statement and the support for the corrected statement.

f) Is it correct that if an existing OGE aerial line when it was originally constructed was built outside of the then-existing road right-of-way, the government agency will pay a majority of the cost of relocating that OGE aerial line (other than for "betterment"), if that existing OGE aerial line must be relocated to clear the way for a government project? If this is not a correct statement, please provide the corrected statement and the support for the corrected statement.

Response*:

a. Please see **AG 22-6_Att1**.

b. The attachment to this response is considered confidential. Copies of the confidential response will be provided to those parties that have signed the protective order.

c. The attachments to this response are considered confidential. Copies of the confidential response will be provided to those parties that have signed the protective order. There is a small portion of the project for which the City is reimbursing the Company the difference between overhead and underground due to the upgrade that is necessary due to not obtaining enough Right of Way (ROW). For that portion, the overhead cost would be

\$15,393.88. The underground cost for that same portion is \$31,244.57. The difference of \$15,850.69, is the portion the City paying.

- d. Yes, the existing line was built within the then-existing road ROW.
- e. Yes, it is correct that if OGE built an aerial line within existing road ROW, the government agency will pay little or none of the cost of relocating. In the case of Morgan Road, the government agency (City, in this case) did not provide us adequate space to relocate our facilities. Therefore, we were forced to either acquire private easement or change our design to fit within the ROW constraints. Changing our design to fit within the ROW means that we would have to upgrade the facilities at an additional cost. In either of these cases, private easement or upgrade, we would look to the City for reimbursement of this additional cost due to the fact that the City is not providing enough ROW in which we can relocate our facilities to our standard.
- f. Yes, that is correct.

Response provided by:	<u>Debra Smith</u>
Response provided on:	<u>April 20, 2018</u>
Contact & Phone No:	<u>Jason Bailey</u> <u>405-553-3406</u>

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Cause No. PUD 201700496 Oklahoma Gas and Electric Co.	THIS FILING IS
Exhibit WWD-9, Page 1 of 9	
Item 1: <input type="checkbox"/> An Initial (Original) Submission	OR <input checked="" type="checkbox"/> Resubmission No. _____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)



FERC FINANCIAL REPORT

FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company) Oklahoma Gas and Electric Company	Year/Period of Report End of <u>2015/Q4</u>
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	111,903,430	1,656,999
49	(352) Structures and Improvements	6,242,912	147,502
50	(353) Station Equipment	662,886,929	35,126,462
51	(354) Towers and Fixtures	160,412,923	
52	(355) Poles and Fixtures	828,768,522	20,835,863
53	(356) Overhead Conductors and Devices	566,225,611	4,497,204
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices	110,494	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	585,057	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,337,135,878	62,264,030
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	12,695,223	245,071
61	(361) Structures and Improvements	6,789,470	388,831
62	(362) Station Equipment	588,146,642	15,753,502
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	560,494,083	35,027,188
65	(365) Overhead Conductors and Devices	436,100,352	28,088,069
66	(366) Underground Conduit	190,859,606	14,851,067
67	(367) Underground Conductors and Devices	689,869,562	38,666,802
68	(368) Line Transformers	413,056,809	26,294,812
69	(369) Services	238,424,025	3,616,347
70	(370) Meters	162,575,277	9,741,518
71	(371) Installations on Customer Premises	39,213,363	10,553,633
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	219,537,770	11,050,425
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,557,762,182	194,277,265
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	3,013,909	421,448
87	(390) Structures and Improvements	164,118,211	22,742,669
88	(391) Office Furniture and Equipment	15,089,073	6,110,637
89	(392) Transportation Equipment	75,775,526	8,226,609
90	(393) Stores Equipment	786,704	340,941
91	(394) Tools, Shop and Garage Equipment	10,426,133	1,519,201
92	(395) Laboratory Equipment	12,549,986	615,915
93	(396) Power Operated Equipment	9,074,033	153,575
94	(397) Communication Equipment	22,184,866	464,106
95	(398) Miscellaneous Equipment	6,284,592	308,721
96	SUBTOTAL (Enter Total of lines 86 thru 95)	319,303,033	40,903,822
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	319,303,033	40,903,822
100	TOTAL (Accounts 101 and 106)	9,837,330,352	448,519,157
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	9,837,330,352	448,519,157

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		1,162,766	114,723,195		48
5,181		861,192	7,246,425		49
10,564,896		-1,901,747	685,546,748		50
822,676		588,277	160,178,524		51
3,793,458		-298,800	845,512,127		52
2,588,592		207,992	568,342,215		53
					54
			110,494		55
					56
			585,057		57
17,774,803		619,680	2,382,244,785		58
					59
			12,940,294		60
9,599			7,168,702		61
5,542,548		-34,519	598,323,077		62
					63
3,314,224		-146	592,206,901		64
3,244,225		-35	460,944,161		65
387,621		-397	205,322,655		66
2,990,434		-1,201	725,544,729		67
5,122,957			434,228,664		68
172,888		-1,172	241,866,312		69
1,153,916		3,694	171,166,573		70
884,411			48,882,565		71
					72
1,502,671		-27	229,085,497		73
					74
24,325,494		-33,803	3,727,680,150		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		-221,065	3,214,292		86
4,508,247		-4,404,900	177,947,733		87
1,589,102			19,610,608		88
3,450,505		-109,520	80,442,110		89
42,386		-3,802	1,081,457		90
570,316		-124,829	11,250,189		91
931,980			12,233,921		92
404,435		144,403	8,967,576		93
62,533		3,802	22,590,241		94
451,403			6,141,910		95
12,010,907		-4,715,911	343,480,037		96
					97
					98
12,010,907		-4,715,911	343,480,037		99
107,493,668	5,510,937	-4,749,714	10,179,117,064		100
					101
					102
					103
107,493,668	5,510,937	-4,749,714	10,179,117,064		104

Cause No. PUD 201700496	THIS FILING IS
Oklahoma Gas and Electric Co.	
Exhibit WWD-9, Page 4 of 9	
Item 1: <input checked="" type="checkbox"/> An Initial (Original) Submission	OR <input type="checkbox"/> Resubmission No. _____

Form 1 Approved
 OMB No.1902-0021
 (Expires 12/31/2019)
 Form 1-F Approved
 OMB No.1902-0029
 (Expires 12/31/2019)
 Form 3-Q Approved
 OMB No.1902-0205
 (Expires 12/31/2019)



FERC FINANCIAL REPORT

FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Oklahoma Gas and Electric Company	End of <u>2016/Q4</u>

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	114,723,195	2,322,992
49	(352) Structures and Improvements	7,246,425	-543,919
50	(353) Station Equipment	685,546,748	38,866,288
51	(354) Towers and Fixtures	160,178,524	1,616,222
52	(355) Poles and Fixtures	845,512,127	59,769,482
53	(356) Overhead Conductors and Devices	568,342,215	21,103,080
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices	110,494	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	585,057	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,382,244,785	123,134,145
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	12,940,294	234,803
61	(361) Structures and Improvements	7,168,702	114,165
62	(362) Station Equipment	598,323,077	18,889,853
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	592,206,901	27,831,912
65	(365) Overhead Conductors and Devices	460,944,161	26,784,105
66	(366) Underground Conduit	205,322,655	13,499,436
67	(367) Underground Conductors and Devices	725,544,729	42,230,792
68	(368) Line Transformers	434,228,664	26,002,579
69	(369) Services	241,866,312	2,710,197
70	(370) Meters	171,166,573	9,520,087
71	(371) Installations on Customer Premises	48,882,585	5,430,828
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	229,085,497	11,443,726
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,727,680,150	184,692,483
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	3,214,292	
87	(390) Structures and Improvements	177,947,733	1,436,053
88	(391) Office Furniture and Equipment	19,610,608	10,929,716
89	(392) Transportation Equipment	80,442,110	4,408,477
90	(393) Stores Equipment	1,081,457	315,381
91	(394) Tools, Shop and Garage Equipment	11,250,189	779,341
92	(395) Laboratory Equipment	12,233,921	159,715
93	(396) Power Operated Equipment	8,967,576	1,891,964
94	(397) Communication Equipment	22,590,241	1,953,421
95	(398) Miscellaneous Equipment	6,141,910	240,926
96	SUBTOTAL (Enter Total of lines 86 thru 95)	343,480,037	22,114,994
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	343,480,037	22,114,994
100	TOTAL (Accounts 101 and 106)	10,179,117,064	435,677,245
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	10,179,117,064	435,677,245

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				47
			117,046,187	48
			6,702,506	49
830,583			723,582,453	50
			161,794,746	51
1,070,215			904,211,394	52
91,539			589,353,756	53
				54
			110,494	55
				56
			585,057	57
1,992,337			2,503,386,593	58
				59
461			13,174,636	60
919			7,281,948	61
1,509,978			615,702,952	62
				63
3,528,127		-5,598	616,505,088	64
3,170,007			484,558,259	65
592,369			218,229,722	66
3,353,257			764,422,264	67
4,721,402			455,509,841	68
145,886			244,430,623	69
199,234			180,487,426	70
587,087			53,726,326	71
				72
1,289,829		5,598	239,244,992	73
				74
19,098,556			3,893,274,077	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
27,255		-36,246	3,150,791	86
252,878		-254,058	178,876,850	87
429,336		65,521	30,176,509	88
2,836,007		5,805,525	87,820,105	89
56,362		45,726	1,386,202	90
423,753		3,475	11,609,252	91
322,473			12,071,163	92
337,850		2,129,263	12,650,953	93
75,668		2,094,659	26,562,653	94
149,554		6,080	6,239,362	95
4,911,136		9,859,945	370,543,840	96
				97
				98
4,911,136		9,859,945	370,543,840	99
52,304,067		10,132,696	10,572,622,938	100
				101
				102
				103
52,304,067		10,132,696	10,572,622,938	104

Cause No. PUD 201700496 THIS FILING IS	
Oklahoma Gas and Electric Co.	
Exhibit WWD-9, Page 7 of 9	
Item 1: <input checked="" type="checkbox"/> An Initial (Original) Submission	OR <input type="checkbox"/> Resubmission No. ____

Form 1 Approved
 OMB No.1902-0021
 (Expires 12/31/2019)
 Form 1-F Approved
 OMB No.1902-0029
 (Expires 12/31/2019)
 Form 3-Q Approved
 OMB No.1902-0205
 (Expires 12/31/2019)



FERC FINANCIAL REPORT

FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Oklahoma Gas and Electric Company	End of <u>2017/Q4</u>

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	117,046,187	9,075,820
49	(352) Structures and Improvements	6,702,506	
50	(353) Station Equipment	723,582,453	59,214,198
51	(354) Towers and Fixtures	161,794,746	1,727,867
52	(355) Poles and Fixtures	904,211,394	37,382,756
53	(356) Overhead Conductors and Devices	589,353,756	14,910,347
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices	110,494	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	585,057	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,503,386,593	122,310,988
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	13,174,636	323,785
61	(361) Structures and Improvements	7,281,948	255,658
62	(362) Station Equipment	615,702,952	33,941,670
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	616,505,088	31,894,350
65	(365) Overhead Conductors and Devices	484,558,259	21,916,681
66	(366) Underground Conduit	218,229,722	10,183,260
67	(367) Underground Conductors and Devices	764,422,264	37,256,034
68	(368) Line Transformers	455,509,841	23,476,350
69	(369) Services	244,430,623	3,675,792
70	(370) Meters	180,487,426	9,498,091
71	(371) Installations on Customer Premises	53,726,326	2,755,030
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	239,244,992	9,730,343
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,893,274,077	184,907,044
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	3,150,791	30,772
87	(390) Structures and Improvements	178,876,850	7,510,830
88	(391) Office Furniture and Equipment	30,176,509	10,063,441
89	(392) Transportation Equipment	87,820,105	3,840,720
90	(393) Stores Equipment	1,386,202	199,999
91	(394) Tools, Shop and Garage Equipment	11,609,252	819,373
92	(395) Laboratory Equipment	12,071,163	352,215
93	(396) Power Operated Equipment	12,650,953	-23,537
94	(397) Communication Equipment	26,562,653	396,614
95	(398) Miscellaneous Equipment	6,239,362	372,450
96	SUBTOTAL (Enter Total of lines 86 thru 95)	370,543,840	23,562,877
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	370,543,840	23,562,877
100	TOTAL (Accounts 101 and 106)	10,572,622,938	488,125,647
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	10,572,622,938	488,125,647

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				47
			126,122,007	48
			6,702,506	49
2,117,628			780,679,023	50
131,836			163,390,777	51
1,795,490		-2,152	939,796,508	52
331,955		2,152	603,934,300	53
				54
			110,494	55
				56
			585,057	57
4,376,909			2,621,320,672	58
				59
12,510		-7,846	13,478,065	60
5,066			7,532,540	61
7,908,697			641,735,925	62
				63
3,563,841			644,835,597	64
3,726,716			502,748,224	65
517,256			227,895,726	66
2,751,545			798,926,753	67
4,879,734			474,106,457	68
2,023,361			246,083,054	69
831,162			189,154,355	70
314,076			56,167,280	71
				72
865,262			248,110,073	73
				74
27,399,226		-7,846	4,050,774,049	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			3,181,563	86
128,559		7,100,335	193,359,456	87
477,735		13,432,887	53,195,102	88
3,556,514			88,104,311	89
210,955			1,375,246	90
432,667			11,995,958	91
323,658			12,099,720	92
31,790			12,595,626	93
		863,815	27,823,082	94
97,635			6,514,177	95
5,259,513		21,397,037	410,244,241	96
				97
				98
5,259,513		21,397,037	410,244,241	99
134,590,566		106,394,910	11,032,552,929	100
				101
				102
				103
134,590,566		106,394,910	11,032,552,929	104

Attorney General
Data Request AG-1
Cause No. PUD 201700496

1-3 General: Please provide working copies of all computer models, spreadsheets, workpapers and calculations used by each Company witness or used to prepare any submission in this Cause. If any computation is prepared in a separate model or spreadsheet from the primary work paper, those supplemental models and spreadsheets are also to be provided in response to this request. If the Company omits any electronic model, spreadsheet or document supporting any adjustment, please provide an explanation as to why the excluded information is not necessary support for the Company's application. The spreadsheets and models should be provided in Excel-compatible format and be fully functional with all formulas intact.

Response*: Please see attachment **AG 1-3_Att** for the working copies provided by Company witnesses Burch, Evans, Howell, Morin, Satterwhite, Spanos, and Webster. Please also see the Company's One Drive "Workpapers" folder at the following link ([PUD 2017-496 Rate Case One Drive](#)), which was provided on the filing date, for the working copies provided by Company witnesses Bailey, Knight, Merrill, Rowlett, Thenmadathil, and Wai/Scott.

Company witnesses Kopp and Webster have working copies that are considered confidential. Copies of the confidential information will be provided to those parties that have signed the protective order.

Company witness Nickell's working copies are considered Highly Sensitive Confidential Information and may be viewed at OG&E Corporate Headquarters by appointment, during normal business hours.

Response provided by:	<u>Donald Rowlett</u>
Response provided on:	<u>January 31, 2018</u>
Contact & Phone No:	<u>Jason Bailey 405-553-3406</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

AccountNumber	GroupNumber	CompanyNumber	TransactionCode	TransactionYear	InstallationYear	Amount	AdjustedTY
37300			0	2017	1958	(7,443,226.04)	
37300			0	2017	1959	(17,245.01)	
37300			0	2017	1960	(9,916.22)	
37300			0	2017	1961	(13,725.04)	
37300			0	2017	1962	(6,063.69)	
37300			0	2017	1963	(9,769.78)	
37300			0	2017	1964	(6,043.56)	
37300			0	2017	1965	(3,675.43)	
37300			0	2017	1966	(4,053.74)	
37300			0	2017	1967	(3,377.68)	
37300			0	2017	1968	(2,481.93)	
37300			0	2017	1969	(2,557.37)	
37300			0	2017	1970	(9,100.32)	
37300			0	2017	1971	(63,587.65)	
37300			0	2017	1972	(104,139.17)	
37300			0	2017	1973	(32,851.98)	
37300			0	2017	1974	(25,184.09)	
37300			0	2017	1975	(33,644.87)	
37300			0	2017	1976	(11,511.08)	
37300			0	2017	1977	(27,139.04)	
37300			0	2017	1978	(29,183.61)	
37300			0	2017	1979	(49,789.90)	
37300			0	2017	1980	(28,885.53)	
37300			0	2017	1981	(33,028.52)	
37300			0	2017	1982	(72,806.96)	
37300			0	2017	1983	(64,091.73)	
37300			0	2017	1984	(47,923.65)	
37300			0	2017	1985	(131,829.60)	
37300			0	2017	1986	(62,968.98)	
37300			0	2017	1987	(42,384.72)	
37300			0	2017	1988	(15,410.15)	
37300			0	2017	1989	(42,472.83)	
37300			0	2017	1990	(45,158.10)	
37300			0	2017	1991	(43,413.21)	
37300			0	2017	1992	(44,620.35)	
37300			0	2017	1993	(43,541.70)	
37300			0	2017	1994	(55,587.41)	
37300			0	2017	1995	(46,314.41)	
37300			0	2017	1996	(68,586.63)	
37300			0	2017	1997	(83,477.64)	
37300			0	2017	1998	(60,333.01)	
37300			0	2017	1999	(82,972.85)	
37300			0	2017	2000	(59,895.71)	
37300			0	2017	2001	(63,188.36)	
37300			0	2017	2002	(61,464.81)	
37300			0	2017	2003	(59,727.35)	
37300			0	2017	2004	(58,605.66)	
37300			0	2017	2005	(69,940.81)	
37300			0	2017	2006	(76,346.36)	
37300			0	2017	2007	(80,602.00)	
37300			0	2017	2008	(70,874.16)	
37300			0	2017	2009	(55,810.43)	
37300			0	2017	2010	(43,144.32)	
37300			0	2017	2011	(34,659.92)	
37300			0	2017	2012	(40,447.42)	
37300			0	2017	2013	(39,858.97)	
37300			0	2017	2014	(36,867.43)	
37300			0	2017	2015	(38,405.82)	
37300			0	2017	2016	(36,085.29)	

Total 2017 Estimated Retirements Added by Mr. Dunkel

(9,950,000.00)

Source: Response AG 1-3 OGE Provided Excel "OGE2016-Acct 373 Projected Data"

Attorney General of Oklahoma
Data Request AG-13
Cause No. PUD 201700496

13-15 Please refer to the direct testimony of John J. Spanos filed in Cause No. PUD 201500273. At page 10, lines 12 to 20, Mr. Spanos testified to the following:

Q. Was there any life analysis performed to include future plans?

A. Yes. The Company has planned a conversion to LED lighting in Account 373, Street Lighting and Signal Systems. The program is scheduled to take 9 to 10 years for full implementation. However, not all assets within the account will be replaced. The life analyses for Account 373, Street Lighting and Signal Systems, set forth on pages VII-101 through VII-104 of Direct Exhibit JJS-2 includes the historical analyses from 1997 through 2014 as well as the projected analyses for 2015 through 2024. The 25-LJ survivor curve represents the most appropriate life characteristics of past and future expectations for street lighting.

Please provide the data file used in Cause No. PUD 201500273 that shows the projected data for 2015 through 2024, described above. Please provide the file in Excel-compatible format with all formulas fully functional and intact, if available. The file should be available in a form similar to “OGE2016- Acct 373 Projected data.xlsx” provided in response to AG-OGE-1-3 in the current proceeding.

Response*: Please see attachment AG 13-15_Att which sets forth the projected data presented in the Cause No. PUD 201500273.

Response provided by:	<u>John Spanos</u>
Response provided on:	<u>March 22, 2018</u>
Contact & Phone No:	<u>Jason Bailey 405-553-3406</u>

***By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.**

AccountNumber	GroupNumber	CompanyNumber	TransactionCode	TransactionYear	InstallationYear	Amount
37300	0	37	0	2016	1958	(1,231,133.97)
37300	0	37	0	2016	1959	(5,479.04)
37300	0	37	0	2016	1960	(5,801.27)
37300	0	37	0	2016	1961	(12,136.84)
37300	0	37	0	2016	1962	(7,118.07)
37300	0	37	0	2016	1963	(15,368.76)
37300	0	37	0	2016	1964	(10,821.96)
37300	0	37	0	2016	1965	(7,503.96)
37300	0	37	0	2016	1966	(10,501.45)
37300	0	37	0	2016	1967	(8,090.09)
37300	0	37	0	2016	1968	(7,346.31)
37300	0	37	0	2016	1969	(8,447.16)
37300	0	37	0	2016	1970	(35,699.86)
37300	0	37	0	2016	1971	(260,805.57)
37300	0	37	0	2016	1972	(469,978.07)
37300	0	37	0	2016	1973	(152,525.33)
37300	0	37	0	2016	1974	(106,466.07)
37300	0	37	0	2016	1975	(135,111.50)
37300	0	37	0	2016	1976	(44,234.94)
37300	0	37	0	2016	1977	(99,739.81)
37300	0	37	0	2016	1978	(105,554.09)
37300	0	37	0	2016	1979	(175,298.84)
37300	0	37	0	2016	1980	(111,421.58)
37300	0	37	0	2016	1981	(112,768.44)
37300	0	37	0	2016	1982	(245,286.85)
37300	0	37	0	2016	1983	(216,180.82)
37300	0	37	0	2016	1984	(164,134.18)
37300	0	37	0	2016	1985	(451,045.57)
37300	0	37	0	2016	1986	(219,413.23)
37300	0	37	0	2016	1987	(153,347.04)
37300	0	37	0	2016	1988	(56,967.36)
37300	0	37	0	2016	1989	(157,728.42)
37300	0	37	0	2016	1990	(171,787.61)
37300	0	37	0	2016	1991	(168,774.07)
37300	0	37	0	2016	1992	(176,792.01)
37300	0	37	0	2016	1993	(176,578.03)
37300	0	37	0	2016	1994	(232,915.57)
37300	0	37	0	2016	1995	(203,785.23)
37300	0	37	0	2016	1996	(310,507.21)
37300	0	37	0	2016	1997	(394,169.29)
37300	0	37	0	2016	1998	(299,749.33)
37300	0	37	0	2016	1999	(432,992.55)
37300	0	37	0	2016	2000	(331,610.84)
37300	0	37	0	2016	2001	(365,167.74)
37300	0	37	0	2016	2002	(364,009.43)
37300	0	37	0	2016	2003	(359,918.58)
37300	0	37	0	2016	2004	(348,000.47)
37300	0	37	0	2016	2005	(398,804.98)
37300	0	37	0	2016	2006	(404,538.38)
37300	0	37	0	2016	2007	(371,360.97)
37300	0	37	0	2016	2008	(270,507.18)
37300	0	37	0	2016	2009	(163,234.09)
37300	0	37	0	2016	2010	(95,774.63)
37300	0	37	0	2016	2011	(57,385.38)
37300	0	37	0	2016	2012	(50,192.72)
37300	0	37	0	2016	2013	(32,286.02)
37300	0	37	0	2016	2014	(15,701.24)

Total 2016 Estimated Retirements Added by Mr. Dunkel

(11,000,000.00)

Source: Response AG 13-15 OGE Provided Excel "AG 13-15_Att"

AccountNumber	GroupNumber	CompanyNumber	TransactionCode	TransactionYear	InstallationYear	Amount
37300	0	37	0	2015	1958	(6,246,446.25)
37300	0	37	0	2015	1959	(15,371.45)
37300	0	37	0	2015	1960	(10,647.15)
37300	0	37	0	2015	1961	(16,499.20)
37300	0	37	0	2015	1962	(7,595.44)
37300	0	37	0	2015	1963	(13,505.69)
37300	0	37	0	2015	1964	(8,020.30)
37300	0	37	0	2015	1965	(4,791.27)
37300	0	37	0	2015	1966	(5,873.82)
37300	0	37	0	2015	1967	(5,027.61)
37300	0	37	0	2015	1968	(3,211.85)
37300	0	37	0	2015	1969	(3,345.02)
37300	0	37	0	2015	1970	(12,892.99)
37300	0	37	0	2015	1971	(86,411.71)
37300	0	37	0	2015	1972	(143,775.71)
37300	0	37	0	2015	1973	(47,141.82)
37300	0	37	0	2015	1974	(36,263.94)
37300	0	37	0	2015	1975	(48,855.43)
37300	0	37	0	2015	1976	(16,875.27)
37300	0	37	0	2015	1977	(40,057.35)
37300	0	37	0	2015	1978	(44,286.89)
37300	0	37	0	2015	1979	(76,319.39)
37300	0	37	0	2015	1980	(45,157.84)
37300	0	37	0	2015	1981	(53,011.93)
37300	0	37	0	2015	1982	(118,369.60)
37300	0	37	0	2015	1983	(106,720.30)
37300	0	37	0	2015	1984	(82,931.01)
37300	0	37	0	2015	1985	(233,189.97)
37300	0	37	0	2015	1986	(116,105.90)
37300	0	37	0	2015	1987	(83,178.82)
37300	0	37	0	2015	1988	(31,742.56)
37300	0	37	0	2015	1989	(90,434.91)
37300	0	37	0	2015	1990	(101,567.91)
37300	0	37	0	2015	1991	(103,045.44)
37300	0	37	0	2015	1992	(111,338.44)
37300	0	37	0	2015	1993	(114,298.26)
37300	0	37	0	2015	1994	(154,220.56)
37300	0	37	0	2015	1995	(136,935.99)
37300	0	37	0	2015	1996	(209,184.29)
37300	0	37	0	2015	1997	(262,806.10)
37300	0	37	0	2015	1998	(194,979.02)
37300	0	37	0	2015	1999	(270,597.01)
37300	0	37	0	2015	2000	(196,045.94)
37300	0	37	0	2015	2001	(201,358.72)
37300	0	37	0	2015	2002	(184,592.39)
37300	0	37	0	2015	2003	(165,347.86)
37300	0	37	0	2015	2004	(143,435.85)
37300	0	37	0	2015	2005	(145,613.68)
37300	0	37	0	2015	2006	(131,430.65)
37300	0	37	0	2015	2007	(110,660.67)
37300	0	37	0	2015	2008	(79,956.53)
37300	0	37	0	2015	2009	(52,207.19)
37300	0	37	0	2015	2010	(33,159.92)
37300	0	37	0	2015	2011	(19,266.49)
37300	0	37	0	2015	2012	(14,568.68)
37300	0	37	0	2015	2013	(7,274.81)
37300	0	37	0	2015	2014	(2,049.21)

Total 2015 Estimated Retirements Added by Mr. Dunkel

(11,000,000.00)

Source: Response AG 13-15 OGE Provided Excel "AG 13-15_Att1"

Attorney General of Oklahoma
Data Request AG-15
Cause No. PUD 201700496

15-5 Provide copies of any OGE press releases pertaining to OGE converting to LED in street lights or traffic lights from January 1, 2014, to March 31, 2018, including, but not limited to, any press releases that pertain to Oklahoma City.

Response*: OG&E hasn't issued any press releases on its own, but has approved releases issued by other organizations. Attached as **AG 15-5_Att** are those releases along with some LED news stories.

Response provided by: Kathleen O'Shea
Response provided on: March 28, 2018
Contact & Phone No: Jason Bailey 405-553-3406

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

AG 1505 LED streetlight press releases March 21, 2018

OG&E has not issued any press releases on its own; some of the press releases below were issued by other organizations with joint approval from OG&E.

1. Press release issued by City of OKC (joint release with OG&E) – Jan. 3, 2017
“OG&E to demonstrate new streetlight technology in northeast Oklahoma City”
2. Journal Record print article (interview with Scott Milanowski of OG&E) – Jan. 3, 2017
“OG&E to upgrade street lamps with LEDs”
3. Press release by Silver Springs Network (joint release with OG&E) – Jan. 31, 2017
“Oklahoma Gas & Electric Selects Silver Springs Networks for Smart Street Lights Program”
4. Online trade publication – IoT Agenda article (interview with Tony Cooper of OG&E) – Feb. 1, 2017
“Smart streetlight project helps Oklahoma Gas and Electric keep the lights on”
5. KOKH-FOX 25 broadcast news story (interview with Kathleen O’Shea of OG&E) – June 12, 2017
“Streetlights to change to LED in OKC”
6. KFOR-4 (OKC NBC affiliate) broadcast news story (interview with Kathleen O’Shea of OG&E) – Jan. 4, 2017
“New LED streetlights will be installed in Oklahoma City as part of 2-year study”

NEWS RELEASES**OG&E to demonstrate new streetlight technology in northeast Oklahoma City****Post Date:** 01/03/2017 11:19 AM

New OG&E streetlights in two northeast Oklahoma City corridors will give the City and residents two years to evaluate the benefits of advanced light-emitting diode (LED) technology on our streets.

The Oklahoma City Council approved an agreement Tuesday with OG&E that will bring new LED streetlights to parts of the Adventure District and Innovation District that don't have lights now.

OG&E will install 45 advanced LED roadway lights on galvanized steel poles on Remington Place and NE 50th Street between Martin Luther King Jr. Avenue and Interstate 35. A dozen lights will also be installed on NE 8th Street between Research Parkway and Lindsay Avenue.

The lights are more efficient, dimmable, improve nighttime visibility and are connected to a web- and GPS-based management system providing the potential for automated maintenance reports.

The two-year evaluation period will let OG&E and the City test the lights' year-round durability in Oklahoma's weather, and evaluate the lights' effectiveness and cost of operation. After two years, the City has the option to keep the lights or have them replaced with the standard pole and light fixture and begin paying for operation costs.

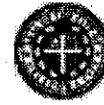
The new advanced LED lights could eventually become the standard option for new and replacement streetlights in Oklahoma City.

- Follow the City of Oklahoma City on Twitter, Facebook, Instagram and more.
- Sign up for the City of OKC News email newsletter and eNotifications.
- Take an online survey and learn more about the 2017 Bond Election.
- Watch City Channel 20 on Cox Cable or live anywhere on YouTube.
- Download the OKC Connect smartphone app for Apple or Android.

Media Contact

Kristy Yager

TWITTER



City of OKC
@cityofokc

MAR 21

Oklahoma City will host a special collection for unwanted computers, tires, ammunition and prescription drugs from...

<https://t.co/RSTs5BnrAA>

Exhibit WWD-11 Page 4 of 4
(405) 297-2550 / (405) 863-2831

kristy.yager@okc.gov

① Cont.

[Return to full list >>](#)

Attorney General of Oklahoma
Data Request AG-15
Cause No. PUD 201700496

15-4 Is it a correct statement that, in an interview televised by Fox 25 on June 12, 2017, Kathleen O'Shea on behalf of OGE, stated the following regarding the installation of LED street lights in Oklahoma City: "We're adopting an attrition strategy" and "Let's start replacing when the old ones hit end of service so it's a slower process"? If this is not a correct statement, please provide the corrected statement and the support for the corrected statement.

Response*: Yes, Kathleen O'Shea did an interview with a Fox 25 news reporter on June 12, 2017 and the report received from the news monitor source contained the quote as referenced above.

Response provided by: Kathleen O'Shea
Response provided on: March 28, 2018
Contact & Phone No: Jason Bailey 405-553-3406

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Attorney General of Oklahoma
Data Request AG-15
Cause No. PUD 201700496

15-6 Is it the policy of OGE to upgrade street lights to LED at a time when the existing light requires service or replacement—for example, when the light has ceased functioning or the bulb is burned out? If not, why not?

Response*: OG&E's policy will be to replace burned out bulbs with similar bulbs if they are in stock. If a replacement bulb is not in stock or the actual light fixture is failed or damaged, the fixture will be replaced with an LED fixture. OG&E intends to deplete in-stock material first to minimize stranded investment cost.

Response provided by: Scott Milanowski
Response provided on: March 28, 2018
Contact & Phone No: Jason Bailey 405-553-3406

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Attorney General of Oklahoma
Data Request AG-15
Cause No. PUD 201700496

15-7 Please provide the percentage of street light bulbs/lamps owned by OGE that, as of December 31, 2017, are LED.

Response*: OG&E has 99 LED lights installed at three pilot sites, and a total of approximately 250,000 street lights on its system. This is approximately 0.04%.

Response provided by: Scott Milanowski
Response provided on: March 28, 2018
Contact & Phone No: Jason Bailey 405-553-3406

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Attorney General of Oklahoma
Data Request AG-14
Cause No. PUD 201700496

14-10 Of those instances in 2017 in which the Company converted an existing street light to LED from a different light type, and the Company was not working on that pole or light for any reason other than to convert to LED, in what percent of those cases did the Company have to remove and replace the pole? The response to this question should be limited to facilities whose costs are recorded in Account 373.

Response*: 0%. All were new installations where no pole previously existed.

Response provided by: Scott Milanowski
Response provided on: March 26, 2018
Contact & Phone No: Jason Bailey 405-553-3406

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Attorney General of Oklahoma
Data Request AG-14
Cause No. PUD 201700496

14-12 As of December 31, 2016, what is the dollar amount of plant in service for street light heads (“luminaires”) in Account 373?

Response*: The amount of street light heads (Luminaires) in Account 373 at 12/31/2016 is \$105,478,925.

Response provided by: Carla Chupik
Response provided on: March 26, 2018
Contact & Phone No: Jason Bailey 405-553-3406

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Attorney General of Oklahoma
Data Request AG-14
Cause No. PUD 201700496

14-13 As of December 31, 2016, what was the total dollar amount of plant in service in Account 373?

Response*: The total dollar amount of plant in service in Account 373 at December 31, 2016 is \$239,244,991.03.

Response provided by: Carla Chupik
Response provided on: March 26, 2018
Contact & Phone No: Jason Bailey 405-553-3406

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Public Utility Depreciation Practices

August 1996



Compiled and Edited by
Staff Subcommittee on Depreciation of
The Finance and Technology Committee
of the
National Association of Regulatory Utility Commissioners

Published by

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Telephone (202) 898-2200
Facsimile (202) 898-2213

CHAPTER VIII

ACTUARIAL LIFE ANALYSES

Knowing what happened yesterday may help one to better understand what is happening today and what may happen tomorrow. This is also true with depreciation studies. Historical life analysis is the study of past occurrences that may be used to indicate the future survivor characteristics of property. Accumulation of suitable data is essential in an historical life analysis. As discussed in the previous chapter, the detail available in the data determines the kinds of analyses (actuarial v. simulation) that can be performed. Understanding the data is necessary in order to assess the limitations and application of the data in reflecting future events. Informed judgment plays a major role in determining how the data should be interpreted and used.

Actuarial analysis is the process of using statistics and probability to describe the retirement history of property. The process may be used as a basis for estimating the probable future life characteristics of a group of property.

Actuarial analysis requires information in greater detail than do other life analysis models (e.g., turnover, simulation) and, as a result, may be impractical to implement for certain accounts (see Chapter VII). However, for accounts for which application of actuarial analysis is practical, it is a powerful analytical tool and, therefore, is generally considered the preferred approach.

Actuarial analysis objectively measures how the company has retired its investment. The analyst must then judge whether this historical view depicts the future life of the property in service. The analyst takes into consideration various factors, such as changes in technology, services provided, or capital budgets.

Mortality History

The purpose of actuarial analysis is to analyze the life characteristics of the utility's property using the historical data contained in the Continuing Property Records (CPR) (see Chapter III). In order to be used in actuarial analyses, the database must contain the property's year of installation (i.e., vintage) and year of retirement. Since the property records are maintained primarily for purposes other than depreciation studies (e.g., for capital budgeting or to accurately reflect a utility's plant), they may require adjustment before use in a depreciation study.

The Treatment of Adjustments and Transfers

The company's property records may contain adjusting entries and transfers (see Chapter III). In the treatment of these adjustments and transfers for preparing life tables, all plant

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PUBLIC UTILITY DEPRECIATION PRACTICES

Gross Additions

Plant additions made during an accounting period. These additions do not include adjustments, transfers, and reclassifications applicable to plant placed in a previous year.

Gross Salvage

The amount recorded for the property retired due to the sale, reimbursement, or reuse of the property.

Group Depreciation

In depreciation accounting, a procedure under which depreciation charges are accrued on the basis of the original cost of all property included in each depreciable group.

h Curves

A system of mathematically-developed, generalized survivor curves based on the truncated normal distribution (curve). The h curves are used by the New York Department of Public Service and most New York utilities.

Half-Year Convention

For calculation purposes, the units installed during an age interval are assumed to have been installed simultaneously at the middle of the interval and thus to have an age dating from the middle of the interval during which they were placed in service. See Age Interval.

Harmonic Weighting

See Reciprocal Weighting.

Historical Cost

See Book Cost.

Index of Variation (IV)

The conformance index divided by 1,000. See Conformance Index (CI).

Indirect Weighting

See Reciprocal Weighting.

Installations

See Gross Additions.

Installed Cost

The cost of labor, material, engineering and overhead associated with transporting and delivering, attaching, testing, and preparing a piece of equipment for the purpose for which acquired. These outlays are capitalized as part of the cost of the asset. This is also referred to as in-place cost.

Attorney General of Oklahoma
Data Request AG-14
Cause No. PUD 201700496

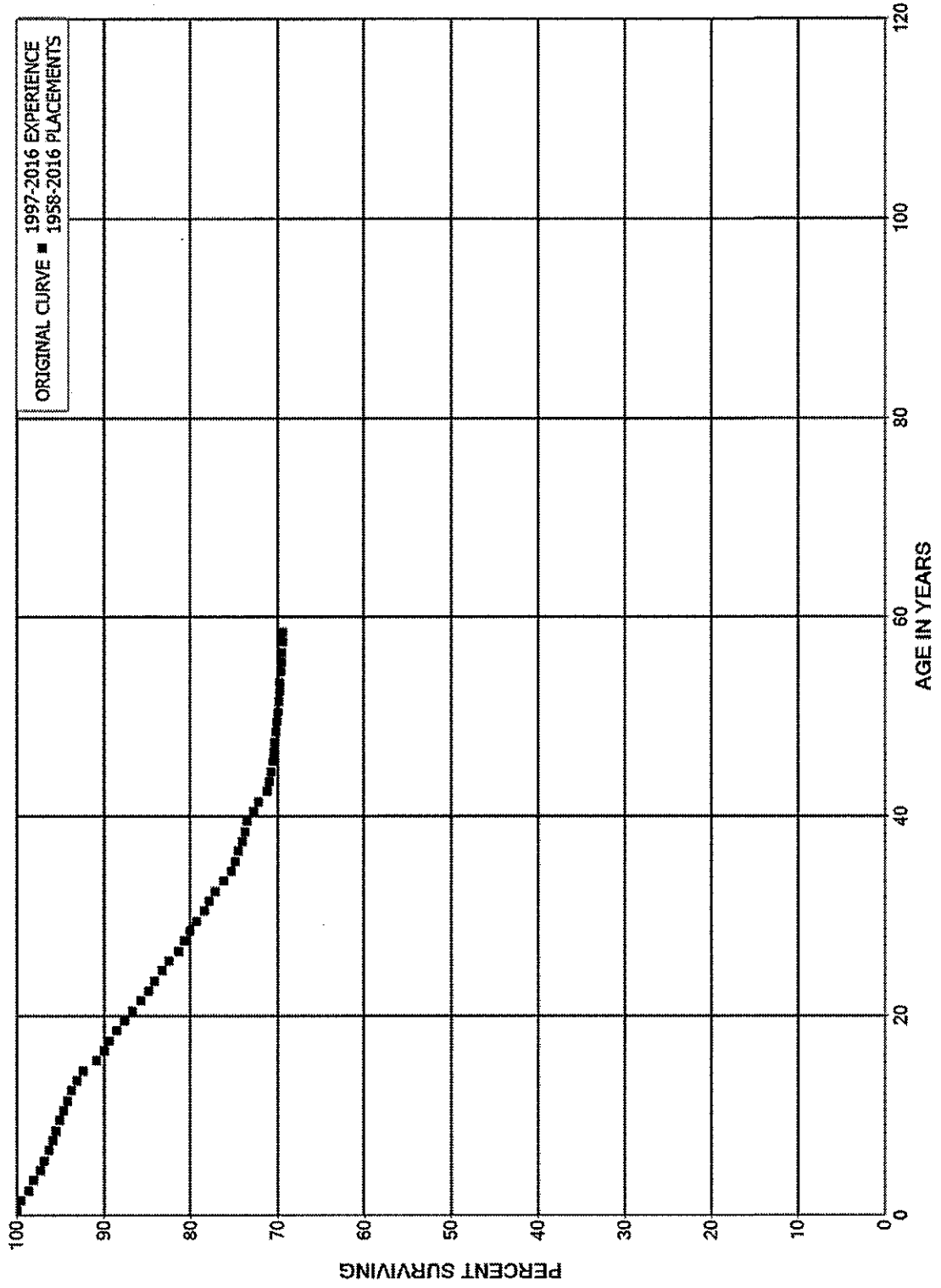
14-5 Please provide pages VII-108 through VII-110 of Exhibit JJS-2, attached to the direct testimony of John J. Spanos, limited to the Experience Band for 1997 to 2016. Do not include any projected data or any alterations to the actual data as recorded in the Company records. If this information is impossible to provide, please provide the data excluding projected data as necessary to produce pages VII-108 through VII-110 with none of the projected data included.

Response*: The historical data for the experience band, 1997-2016, was supplied in the file OGE2016-ServiceLifeData.xlsx. Attachment AG 14-5_Att sets forth pages VII-108 through VII-110 using the 1997 through 2016 experience band.

Response provided by:	<u>John Spanos</u>
Response provided on:	<u>March 26, 2018</u>
Contact & Phone No:	<u>Jason Bailey 405-553-3406</u>

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OKLAHOMA GAS AND ELECTRIC COMPANY
ACCOUNT 373.0 STREET LIGHTING AND SIGNAL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



OKLAHOMA GAS AND ELECTRIC COMPANY

ACCOUNT 373.0 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1958-2016			EXPERIENCE BAND 1997-2016		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	190,639,751	136,992	0.0007	0.9993	100.00
0.5	179,159,620	672,280	0.0038	0.9962	99.93
1.5	167,784,390	1,545,392	0.0092	0.9908	99.55
2.5	156,532,151	973,827	0.0062	0.9938	98.64
3.5	145,706,789	1,033,746	0.0071	0.9929	98.02
4.5	139,992,167	777,378	0.0056	0.9944	97.33
5.5	135,221,128	720,358	0.0053	0.9947	96.79
6.5	129,450,247	593,173	0.0046	0.9954	96.27
7.5	120,908,223	461,537	0.0038	0.9962	95.83
8.5	110,337,764	437,870	0.0040	0.9960	95.46
9.5	98,802,814	466,594	0.0047	0.9953	95.09
10.5	88,733,452	388,613	0.0044	0.9956	94.64
11.5	80,295,035	427,779	0.0053	0.9947	94.22
12.5	73,042,014	519,935	0.0071	0.9929	93.72
13.5	66,241,278	500,383	0.0076	0.9924	93.05
14.5	61,199,360	1,013,106	0.0166	0.9834	92.35
15.5	56,106,795	549,986	0.0098	0.9902	90.82
16.5	53,290,712	329,885	0.0062	0.9938	89.93
17.5	47,174,303	482,311	0.0102	0.9898	89.37
18.5	42,661,484	414,051	0.0097	0.9903	88.46
19.5	37,414,575	384,232	0.0103	0.9897	87.60
20.5	32,865,398	369,624	0.0112	0.9888	86.70
21.5	30,284,428	314,341	0.0104	0.9896	85.73
22.5	27,387,849	216,365	0.0079	0.9921	84.84
23.5	25,285,353	276,996	0.0110	0.9890	84.17
24.5	22,993,843	218,361	0.0095	0.9905	83.24
25.5	21,293,648	263,094	0.0124	0.9876	82.45
26.5	19,487,849	169,048	0.0087	0.9913	81.44
27.5	18,078,555	160,378	0.0089	0.9911	80.73
28.5	17,707,964	168,955	0.0095	0.9905	80.01
29.5	17,235,301	179,919	0.0104	0.9896	79.25
30.5	15,850,741	108,503	0.0068	0.9932	78.42
31.5	11,964,019	111,838	0.0093	0.9907	77.89
32.5	10,595,481	135,905	0.0128	0.9872	77.16
33.5	8,916,050	107,218	0.0120	0.9880	76.17
34.5	18,839,863	107,687	0.0057	0.9943	75.25
35.5	18,063,563	80,900	0.0045	0.9955	74.82
36.5	17,461,602	91,385	0.0052	0.9948	74.49
37.5	38,962,991	212,135	0.0054	0.9946	74.10
38.5	49,955,464	160,232	0.0032	0.9968	73.69

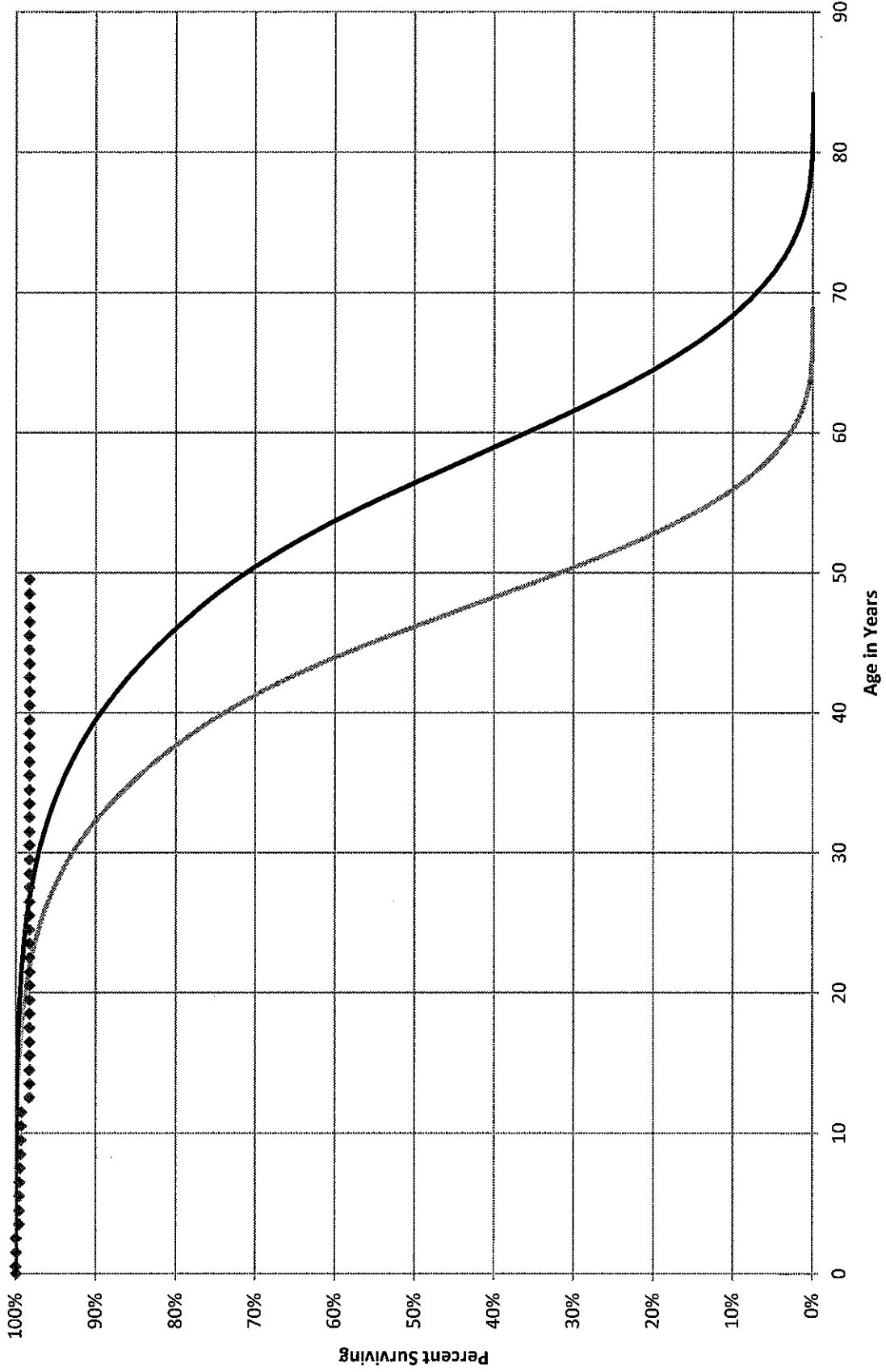
OKLAHOMA GAS AND ELECTRIC COMPANY

ACCOUNT 373.0 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

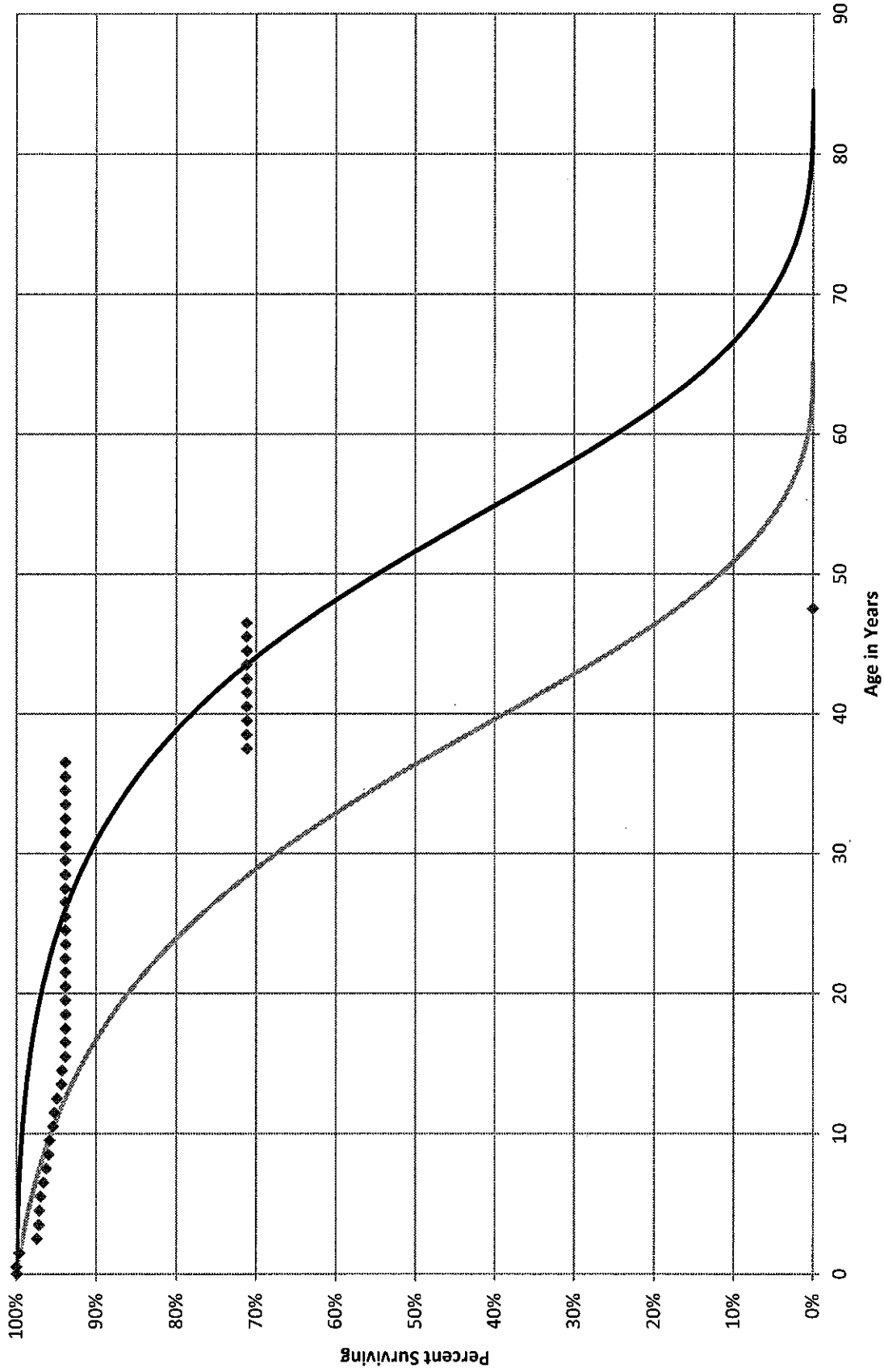
PLACEMENT BAND 1958-2016			EXPERIENCE BAND 1997-2016		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	37,912,760	403,646	0.0106	0.9894	73.46
40.5	37,145,950	260,890	0.0070	0.9930	72.67
41.5	14,791,056	195,572	0.0132	0.9868	72.16
42.5	18,078,212	63,120	0.0035	0.9965	71.21
43.5	17,605,622	68,668	0.0039	0.9961	70.96
44.5	16,331,370	36,282	0.0022	0.9978	70.68
45.5	15,613,801	33,803	0.0022	0.9978	70.53
46.5	15,489,814	25,842	0.0017	0.9983	70.38
47.5	15,440,669	27,906	0.0018	0.9982	70.26
48.5	15,391,906	24,245	0.0016	0.9984	70.13
49.5	15,341,534	27,567	0.0018	0.9982	70.02
50.5	15,284,945	13,895	0.0009	0.9991	69.89
51.5	15,246,511	12,378	0.0008	0.9992	69.83
52.5	15,196,551	18,097	0.0012	0.9988	69.77
53.5	15,122,671	14,253	0.0009	0.9991	69.69
54.5	15,079,053	16,187	0.0011	0.9989	69.63
55.5	15,010,081	19,198	0.0013	0.9987	69.55
56.5	14,962,542	7,508	0.0005	0.9995	69.46
57.5	14,920,480	6,287	0.0004	0.9996	69.43
58.5					69.40

Account 34100



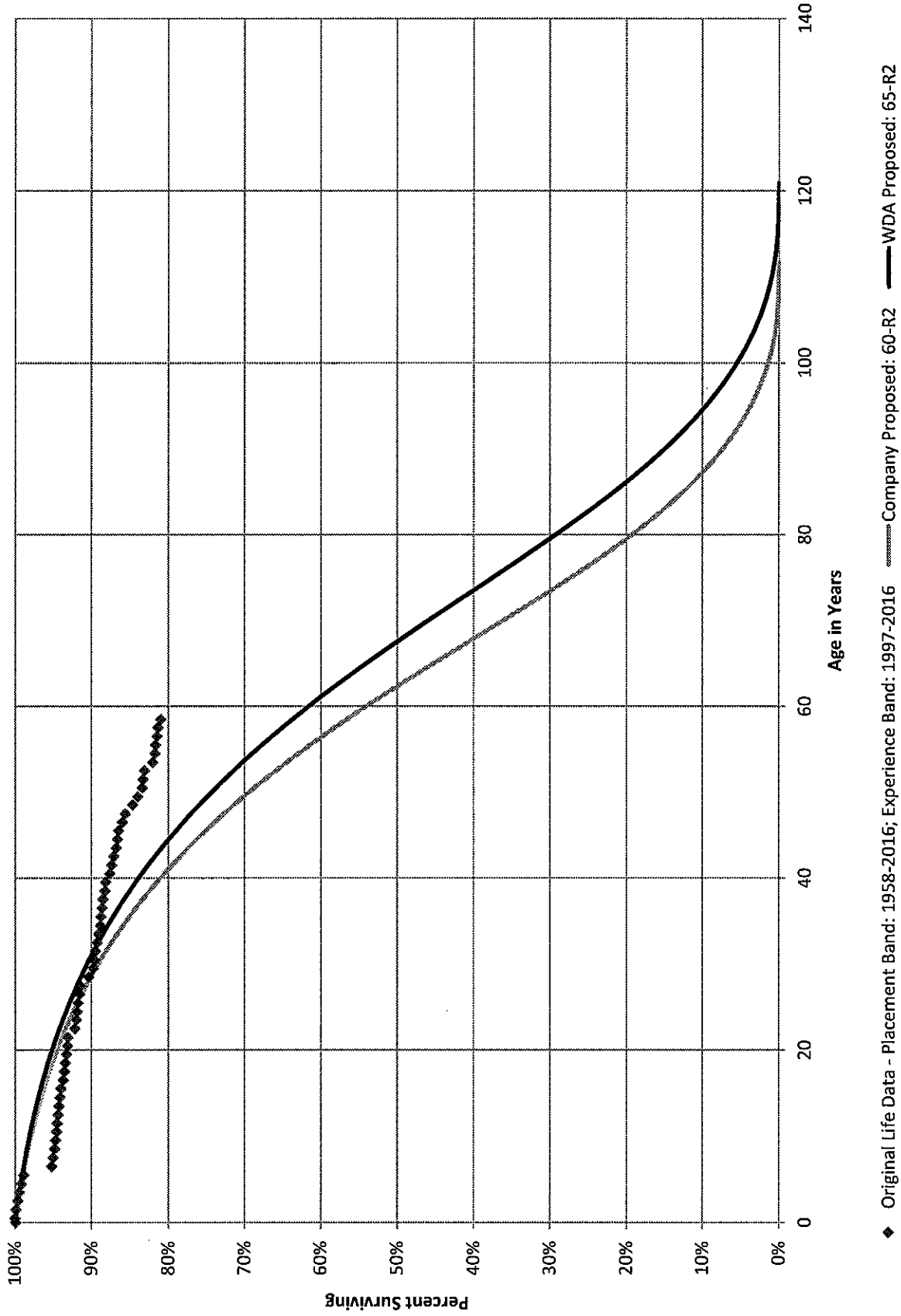
◆ Original Life Data - Placement Band: 1963-2016; Experience Band: 1997-2016 Company Proposed: 45-R4 — WDA Proposed: 55-R4

Account 34300

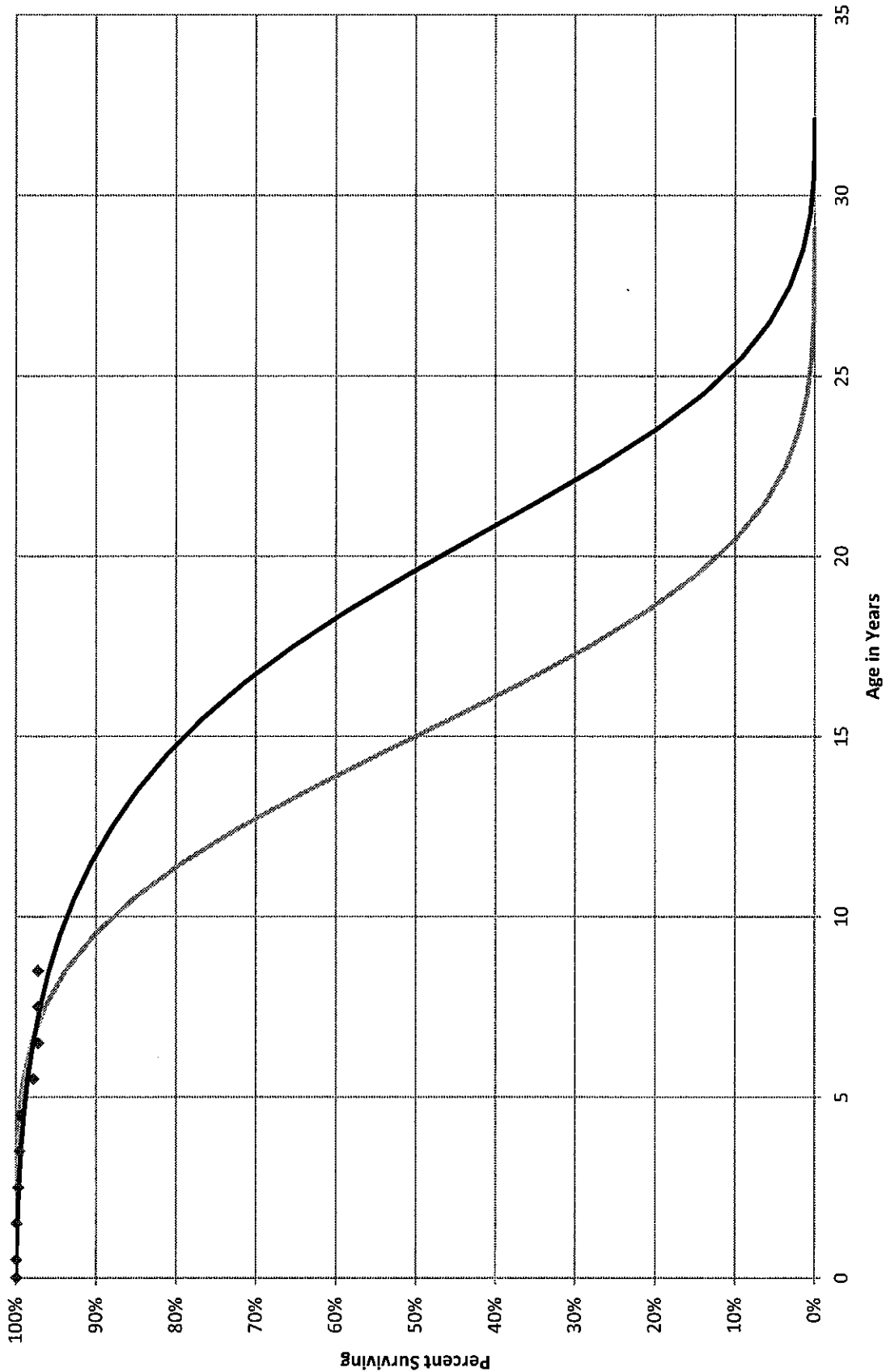


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Account 366, Underground Conduit

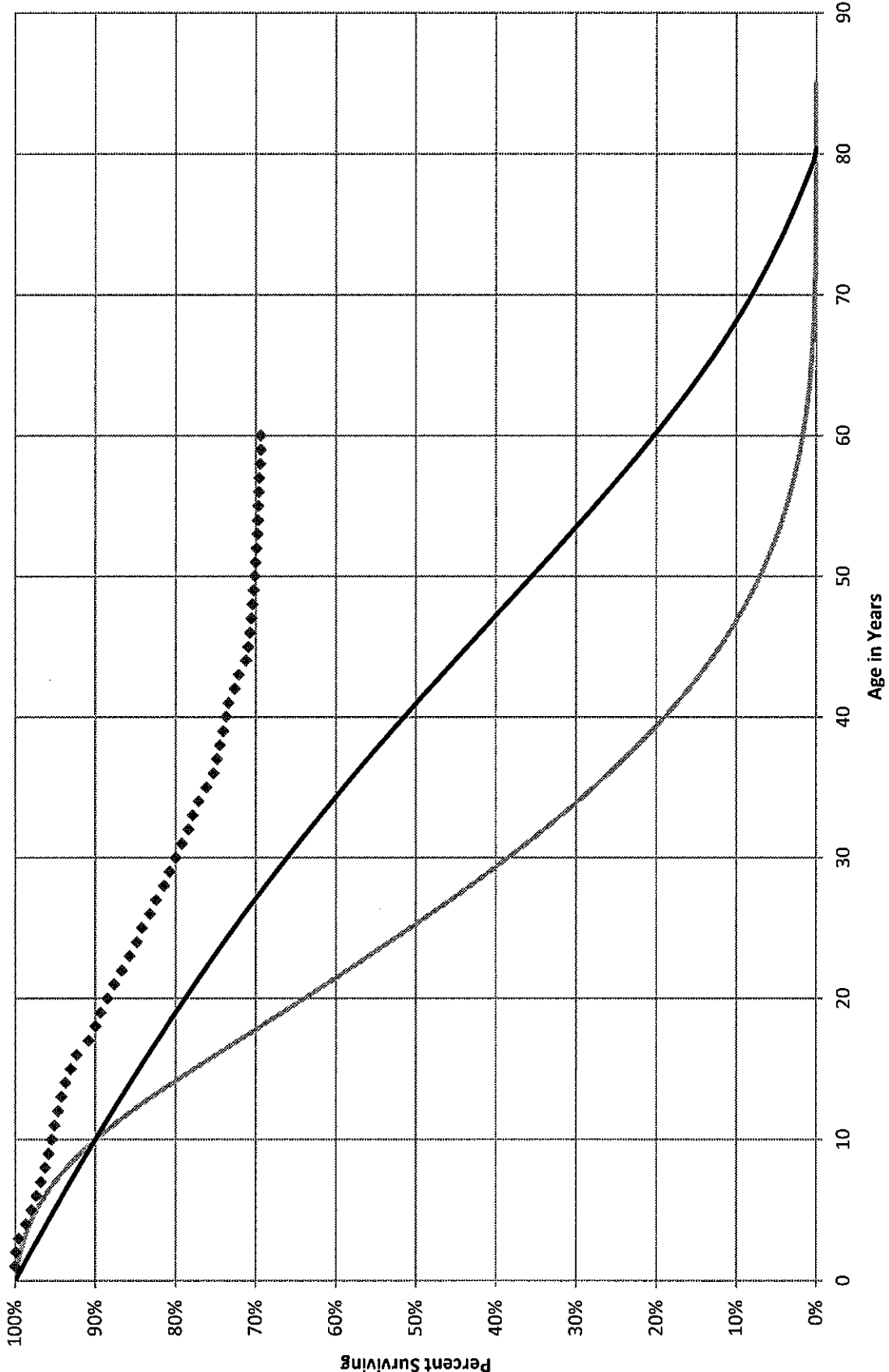


Account 37000



◆ Original Life Data - Placement Band: 2008-2016; Experience Band: 2010-2016 Company Proposed: 15-S2.5 — WDA Proposed: 19-R3

Account 373, Street Lighting and Signal Systems



◆ Original Life Data - Placement Band: 1958-2016; Experience Band: 1997-2016 ◆◆◆ Company Proposed: 27-L1 — WDA Proposed: 40-R0.5

Life Data
 Account 373, Street Lighting and Signal Systems
 Placement Band: 1958-2016
 Experience Band: 1997-2016

Age	BOY Survivors	Total Retirements	Retirement Ratio	Survivor Ratio	Portion Surviving At Start of Age Interval
0	190,639,751	(136,992)	0.00072	0.99928	1.00
0.5	179,159,620	(672,280)	0.00375	0.99625	1.00
1.5	167,784,390	(1,545,392)	0.00921	0.99079	1.00
2.5	156,532,151	(973,827)	0.00622	0.99378	0.99
3.5	145,706,789	(1,033,746)	0.00709	0.99291	0.98
4.5	139,992,167	(777,378)	0.00555	0.99445	0.97
5.5	135,221,128	(720,358)	0.00533	0.99467	0.97
6.5	129,450,247	(593,173)	0.00458	0.99542	0.96
7.5	120,908,223	(461,537)	0.00382	0.99618	0.96
8.5	110,337,764	(437,870)	0.00397	0.99603	0.95
9.5	98,802,814	(466,594)	0.00472	0.99528	0.95
10.5	88,733,452	(388,613)	0.00438	0.99562	0.95
11.5	80,295,035	(427,779)	0.00533	0.99467	0.94
12.5	73,042,014	(519,935)	0.00712	0.99288	0.94
13.5	66,241,278	(500,383)	0.00755	0.99245	0.93
14.5	61,199,360	(1,013,106)	0.01655	0.98345	0.92
15.5	56,106,795	(549,986)	0.00980	0.99020	0.91
16.5	53,290,712	(329,885)	0.00619	0.99381	0.90
17.5	47,174,303	(482,311)	0.01022	0.98978	0.89
18.5	42,661,484	(414,051)	0.00971	0.99029	0.88
19.5	37,414,575	(384,232)	0.01027	0.98973	0.88
20.5	32,865,398	(369,624)	0.01125	0.98875	0.87
21.5	30,284,428	(314,341)	0.01038	0.98962	0.86
22.5	27,387,849	(216,365)	0.00790	0.99210	0.85
23.5	25,285,353	(276,996)	0.01095	0.98905	0.84
24.5	22,993,843	(218,361)	0.00950	0.99050	0.83
25.5	21,293,648	(263,094)	0.01236	0.98764	0.82
26.5	19,487,849	(169,048)	0.00867	0.99133	0.81
27.5	18,078,555	(160,378)	0.00887	0.99113	0.81
28.5	17,707,964	(168,955)	0.00954	0.99046	0.80
29.5	17,235,301	(179,919)	0.01044	0.98956	0.79
30.5	15,850,741	(108,503)	0.00685	0.99315	0.78
31.5	11,964,019	(111,838)	0.00935	0.99065	0.78
32.5	10,595,481	(135,905)	0.01283	0.98717	0.77
33.5	8,916,050	(107,218)	0.01203	0.98797	0.76
34.5	18,839,863	(107,687)	0.00572	0.99428	0.75
35.5	18,063,563	(80,900)	0.00448	0.99552	0.75
36.5	17,461,602	(91,385)	0.00523	0.99477	0.74

Life Data
 Account 373, Street Lighting and Signal Systems
 Placement Band: 1958-2016
 Experience Band: 1997-2016

Age	BOY Survivors	Total Retirements	Retirement Ratio	Survivor Ratio	Portion Surviving At Start of Age Interval
37.5	38,962,991	(212,135)	0.00544	0.99456	0.74
38.5	49,955,464	(160,232)	0.00321	0.99679	0.74
39.5	37,912,760	(403,646)	0.01065	0.98935	0.73
40.5	37,145,950	(260,890)	0.00702	0.99298	0.73
41.5	14,791,056	(195,572)	0.01322	0.98678	0.72
42.5	18,078,212	(63,120)	0.00349	0.99651	0.71
43.5	17,605,622	(68,668)	0.00390	0.99610	0.71
44.5	16,331,370	(36,282)	0.00222	0.99778	0.71
45.5	15,613,801	(33,803)	0.00216	0.99784	0.71
46.5	15,489,814	(25,842)	0.00167	0.99833	0.70
47.5	15,440,669	(27,906)	0.00181	0.99819	0.70
48.5	15,391,906	(24,245)	0.00158	0.99842	0.70
49.5	15,341,534	(27,567)	0.00180	0.99820	0.70
50.5	15,284,945	(13,895)	0.00091	0.99909	0.70
51.5	15,246,511	(12,378)	0.00081	0.99919	0.70
52.5	15,196,551	(18,097)	0.00119	0.99881	0.70
53.5	15,122,671	(14,253)	0.00094	0.99906	0.70
54.5	15,079,053	(16,187)	0.00107	0.99893	0.70
55.5	15,010,081	(19,198)	0.00128	0.99872	0.70
56.5	14,962,542	(7,508)	0.00050	0.99950	0.69
57.5	14,920,480	(6,287)	0.00042	0.99958	0.69
58.5	0	0	0.00000	1.00000	0.69

Source: AG 14-5

Depreciation

Systems

FRANK K. WOLF

W. CHESTER FITCH



IOWA STATE UNIVERSITY PRESS / AMES

Contents

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Preface

THIS book grew from our recognition of the need for a systematic explanation of depreciation using simple, easy-to-follow illustrations. In particular, we examine the portion of depreciation that relates to accounting, specifically as found in public utilities. However, many of the topics covered relate to other applications of depreciation, including valuation of property and taxation. Several conceptual difficulties surround depreciation. One is the lack of understanding that the determination of depreciation involves an intricate system comprising most aspects of the operation of a company. Another is the tendency to view components of the system as being independent of one another. Finally, the use of complicated arithmetic examples, frequently requiring lengthy, time-consuming calculations when explaining ideas, distracts the reader and obfuscates the idea being illustrated.

Asset management includes four actions: (1) the decision, based on analysis of the associated costs and revenues, to acquire property; (2) its acquisition, installation, and associated accounting; (3) its use and related accounting, including the proration of capital expenses to each accounting period; and (4) its retirement and associated accounting. Each action interacts with the other. As management decisions are often based on information from these accounting records, it is essential to exercise careful control over the annual and cumulative results of the depreciation system. This means that the methods used to make estimates of the variables used in calculating and adjusting depreciation should be scrutinized, because they significantly affect the management of the assets of the company.

Investments in capital assets, such as a turbine used to turn an electric

4

Salvage Concepts

If these parameters are not constant, then the estimate of the average life will be affected. See Example 4.1.

Example 4.1. A power plant has a life expectancy of 20 years. The number of units retired increases with age and, possibly, exceeds 100%. If the curve exceeds 100% for a short period, then turns downward, the common solution is to set all points greater than 100% to 100%. If the curve takes in a continuous, upward trend, the parameters must be adjusted.

NOTES

1. This treatment assumes retirements occur uniformly during the final age interval and that the life of the longest lived unit is $ML + .5$ years. If the life of the longest lived unit is known, this value can be used as the end of the final age interval and can be used to calculate the midpoint of the final interval.
2. The maximum life for this Iowa R2 curve is 9.0 years. If the final age interval had been defined to be 8.5 to 9.0 years, the corresponding area would have been 0.21 percent-years, and the total area would have been 300.00 percent-years. See note 1.

SALVAGE can be divided into two components: gross salvage and cost of retiring. *Gross salvage* is the value of a unit retired from service resulting from its sale for scrap or reuse. *Cost of retiring*, also called cost of removal, is the expense incurred to remove the unit from service, including expenses necessary to return the environment to an acceptable condition. Thus, *net salvage* is the gross salvage less the cost of retiring.

The original cost less net salvage is called the *depreciable base*. It represents the capital consumed during the life of the unit and the amount to be recovered through depreciation. If the net salvage is positive, then the capital consumed is less than the original cost. If the net salvage is negative, the capital consumed is greater than the original cost.

When net salvage is zero or near zero, its effect on the depreciable base is nil. However, industrial property exhibits a wide range of salvage, and the effect of salvage on the annual accrual is often substantial. Examples of property yielding positive salvage include land, which is generally assumed to be fully recoverable; buildings and vehicles, which often have significant resale value; and aluminum or copper wire, which has a gross salvage value determined by the intrinsic value of the material. Utility poles and railroad track are often reused, and if the accounting system defines a unit as retired when it is removed from a location, its salvage is determined by its value when it is installed in a new location. On the other hand, underground pipe used for transportation or distribution of gas or water must first be disconnected and then may be filled and capped, or even removed from the ground. These activities are costly because they require significant labor

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Oklahoma Gas and Electric Co.

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and heavy equipment, while the gross salvage is nil or negligible. The result is a net salvage that is often both large and negative. Decommissioning costs of a nuclear generating plant are a contemporary example of an investment with a significant negative net salvage.

Basic salvage concepts must be understood before either the analysis of realized salvage or the forecasting of future salvage can be discussed. Most of these concepts can be applied equally well to either gross salvage or cost of removal, so the term *salvage* is used generically to apply to net salvage, gross salvage, or cost of retiring.

Property placed in service during the same year forms a *vintage group*. The fraction of the vintage group remaining in service is a function of its age and is described by a survivor curve. An underlying functional relationship between the age at retirement and salvage is assumed. A formal development of how salvage changes as property ages is necessary to understand the effect of salvage on depreciation.

A salvage curve is the graph of the salvage ratio versus age. The salvage ratio is the ratio of the salvage to the original cost of the retired unit. The salvage received during any age interval is found by multiplying the salvage ratio for that interval by the dollars retired during that interval. The net salvage ratio is the gross salvage ratio less the cost of retiring salvage ratio.

As one example of a salvage curve, consider property that is easily removed from service and is still functional after retirement. Gross salvage of early retirements will be high if the property is in good condition and the technology is current, because the property will be valuable for sale or reuse. Older retirements would be less valuable because, besides their added wear, they would be competing for use with property that has a more current technology. If the cost of retiring is assumed to be near zero, this model would lead to a net salvage schedule where the salvage ratio is initially near one, but then decreases with age. This example could be expanded to include retirements resulting from damage from an accident or mechanical failure. Because of their physical condition, these units would have a salvage ratio near zero and would lower the overall salvage ratio.

A salvage curve need not decrease with age. The gross salvage of scrap copper, steel, or aluminum typically, because of inflation, increases with age. A cost of retiring that is labor and equipment intensive is another example of a salvage curve that, because of inflation, increases with age. Because this element of salvage is a cost, the term "increases with age" means the salvage becomes more negative with age. Retirement of a utility pole is an example of an activity for which the hours required to remove the pole might remain relatively constant, but the hourly labor rate, and therefore the cost of retirement, would increase as the pole ages.

There are three reasons why it is important to consider salvage as a

function of age, rather than simply using an overall average salvage. First, though the average life (AL) procedure uses an accrual rate based on the average net salvage, the equal life group (ELG) procedure uses the net salvage associated with each equal life group (i.e., salvage by age). Second, the calculated accumulated depreciation (CAD) model must reflect the change in salvage with age if it is to approximate the accumulated provision for depreciation. Because the CAD is the feedback measure used to determine the adequacy of the accumulated provision for depreciation, it is important that the model used be as lifelike as possible. When the remaining life method of adjustment is used, the amount to be recovered is found by adjusting for the future salvage. These first two reasons show that regardless of the system of depreciation used, both the average and the future salvage are required. Finally, considering salvage as a function of age results in a more realistic model and therefore enhances understanding of the depreciation process and aids in forecasting.

THE SALVAGE RATIO

One inherent characteristic of the salvage ratio is that the numerator and denominator are measured in different units; the numerator is measured in dollars at the time of retirement, while the denominator is measured in dollars at the time of installation. Inflation is an economic fact of life and although both numerator and denominator are measured in dollars, the timing of the cash flows reflects different price levels. Consider the pattern of installations and retirements illustrated in Figure 4.1 (see end of chapter).

Two replacement cycles are represented. The installation cost of the first unit is B dollars, it lasts K years, and has a net salvage of V dollars. The salvage ratio of the first unit is $SR(\text{present}) = V/B$. If the cost of the replacement when measured in constant dollars is equal to the cost of the first unit, then the replacement cost measured in inflated dollars is $B \times (1 + p)^K$. The factor $(1 + p)^K$ is called the compound amount factor and equals the value of \$1 after K years when the annual rate of inflation is p. Suppose the life of the replacement unit is L years and during its life the annual rate of inflation is f. Then the future salvage of the replacement is $V \times (1 + f)^L$. The salvage ratio of the replacement is $SR(\text{future}) = V \times (1 + f)^L / B \times (1 + p)^K$. If the past inflation rate p equals the future inflation rate f, and if the life of the original equals that of the replacement, so that K equals L, then the two inflation factors will be equal. The salvage ratio for the replacement will equal V/B , unchanged from the original ratio.

This simple model illustrates two important characteristics of the salvage ratio when the uninflated original cost and uninflated salvage remain

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constant. One is that a change in the inflation rate will cause a change in the salvage ratio. The other is that a change in service life will change the salvage ratio.

The magnitude of the change in salvage ratio depends on p , f , K , and L . As an example, assume that the past inflation rate, p , has been 3% during the past K years, that $V/B = 10\%$, and that the life of the replacement is also K years. Future salvage ratios are determined by the function $10\% \times (1 + f)^j / (1 + p)^j$. Table 4.1 (see end of chapter) shows future salvage ratios for different values of f , the inflation rate during the life of the replacement, and different lives. Notice that if the inflation rate does not change, then the salvage remains unchanged regardless of the life. But if the inflation rate increases, the salvage ratio increases. The longer the life and the greater the change in inflation rate, the more the future salvage ratio deviates from the present 10% ratio. Also note the nonlinear relationship between the salvage ratio and the variables f and K .

Table 4.1 uses future inflation rates that are equal to or greater than the inflation rate during the life of the first unit. If a similar table is constructed using future inflation rates that are equal to or less than the inflation rate during the life of the first unit, then the salvage ratios will be equal to or less than the 10% ratio experienced by the first unit.

Inflation does not affect all segments of the economy equally. The cost of construction, capital equipment, and labor can all increase at different rates. Because the cost of retiring is often labor and equipment intensive, this element of salvage may be closely tied to indexes that reflect labor and equipment costs. Gross salvage values may be closely tied to used equipment costs and are likely to inflate at a different rate than the cost of retiring. Allowing for different inflation rates for capital equipment, gross salvage, and cost of retiring requires modification to the model just presented.

Assume the inflation rates affecting the cost of replacing the first unit and the gross salvage are equal and constant during the replacement cycle; call this rate n . Assume that the cost of retiring inflates at a different rate; call this rate j . After L years the net salvage, V , will equal the (uninflated gross salvage) $\times (1 + n)^L$ - (uninflated cost of retiring) $\times (1 + j)^L$. We can use this model to find how the net salvage ratio is affected when these two inflation rates differ.

As an example, assume that the current gross salvage ratio is 20% and that the current cost of retiring ratio is 10%, so that the net salvage ratio is 20% - 10% or 10%. The future net salvage ratio will be the net salvage at the end of the life of the replacement unit divided by the installed cost of the replacement unit, or $[20\% \times (1 + n)^L - 10\% \times (1 + j)^L] / (1 + n)^L$. Assume that n is 3% and that the lives of the initial unit and the replacement unit both equal L years. Table 4.2 (see end of chapter) shows future

salvage ratios for various values of L and j . Notice that as the difference between n and j becomes larger, the cost of retiring increases faster than the gross salvage. In our example, the cost of retiring catches and exceeds the gross salvage for the larger values of j and the longer lives. The result is negative net salvage.

The salvage ratio as a function of age and inflation rate can be modeled using the equation $(V/B) \times (1 + p)^A$. Table 4.3 (see end of chapter) shows that if the net salvage at time of installation remains constant except for inflation, the observed salvage ratio will vary significantly with time. For example, if the inflation rate was 6% and the salvage ratio at age zero is equal to 10%, the salvage ratio at age 5 would be 13.38% and by age 20 would have increased to 32.07% simply because of inflation. Because the value of the function $(1 + p)^A$ increases rapidly as A becomes large, the factors for a large age (e.g., 40 years) are significantly greater than the 10% initial value.

Recognition of the effect of inflation on salvage will influence the analysis and forecasting of salvage. To find the effect of inflation, it is necessary to understand and calculate the time value of money.

THE SALVAGE CURVE

A salvage curve has been defined as the graph of the salvage ratio as a function of the life of the property. To calculate the average salvage ratio, or the future average salvage ratio at any age, both the salvage curve and the survivor curve must be known.

The net salvage curve is the gross salvage curve less the cost of retiring curve. The method of calculating the average salvage ratio (ASR) is to calculate a weighted average of the salvage ratios for each age interval as shown below.

$$ASR = E(\text{salvage ratio}) = \sum f(i)g(i) \quad \text{for } i = 1, 2, 3, \dots, ML$$

where $f(i)$ = the retirement frequency during age interval i and $g(i)$ = the salvage ratio during age interval, or the ratio evaluated at the midpoint of interval i , where the age intervals and indexes i are defined as

interval i	$x(i)$
0	0.0 \leq service life < 0.5
1	0.5 \leq service life < 1.5
2	1.5 \leq service life < 2.5
3	2.5 \leq service life < 3.5
ML	ML - .5 \leq service life $< ML + .5$

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where $x(i)$ = the midpoint of age interval i and ML = the maximum service life.

The functions $f(i)$ and $g(i)$ also can be described as continuous functions and the equation written in integral form, but this offers little computational advantage. Discrete functions and the age intervals defined above are consistent with the methods used to describe service life.

Two more measures of salvage are

$$\begin{aligned} RSR(i) &= \text{the realized salvage ratio at the start of age interval } i \\ &= \sum f(k)g(k) / \sum f(k) \quad \text{for } k = 1, 2, 3, \dots, i-1 \\ FSR(i) &= \text{the future salvage ratio at the start of age interval } i \\ &= \sum f(k)g(k) / \sum f(k) \quad \text{for } k = i, i+1, i+2, \dots, ML \end{aligned}$$

Suppose that the frequency curve and the salvage curve of a group of property are as shown below. The units are retired at ages 0.25, 1, 2, or 3 years with corresponding salvage ratios of 15%, 10%, 5%, or 0%.

Retirement	Frequency Curve	Salvage Ratio Curve	
$f(0)$	= .20	$g(0)$	= .15
$f(1)$	= .30	$g(1)$	= .10
$f(2)$	= .40	$g(2)$	= .05
$f(3)$	= .10	$g(3)$	= .00
Total	= 1.00		

The average salvage ratio is then calculated as

$$\begin{aligned} ASR &= \sum f(i)g(i) \quad \text{for } i = 1, 2, 3, 4 \\ &= (.20)(.15) + (.30)(.10) + (.40)(.05) + (.20)(0) = 0.08 \text{ or } \\ &\quad 8.0\% \end{aligned}$$

Suppose it is the start of the age interval 1.5 to 2.5 years, so that the index i equals 2. The realized salvage ratio at age 1.5 years, $RSR(2)$, is determined by salvage realized during the first two age intervals, so that.

$$\begin{aligned} RSR(2) &= [(20)(.15) + (30)(.10)] / [20 + 30] = 0.12 \text{ or } 12\% \\ FSR(2) &= [(40)(.05) + (.10)(.00)] / [40 + .10] = 0.04 \text{ or } 4\% \end{aligned}$$

Note that the weighted average of the realized and future salvage ratios equals the average salvage ratio:

$$\begin{aligned} \text{Weight for } RSR(2) &= .20 + .30 = .50 \\ \text{Weight for } FSR(2) &= .40 + .10 = .50 \\ \text{Weighted average salvage} &= ASR = .50 \times 12\% + .50 \times 4\% = 8\% \end{aligned}$$

Table 4.4 (see end of chapter) shows the salvage calculations for an Iowa R2 curve with a 5-year average life (R2-5). Column (c) is the percent retired during the age interval and is found by subtracting successive points on the survivor curve shown in column (b). Column (d) shows the average salvage ratio during the age interval. Note that the salvage ratios in this schedule increase with age.

The salvage observed during the age interval depends on both the salvage per unit and the number of units retired. Column (e) is the product of the salvage ratio and the fraction retired. It equals the salvage during the age interval as a percent of the initial cost. During the age interval 2.5 to 3.5 years, the salvage equals 1.21% of the initial cost. The sum of these amounts is the total salvage over the life of the group expressed as a percent of the initial cost; this is the average salvage ratio, which is 13.46%.

Column (f) is the realized salvage ratio and represents the average that would result if an observer recalculated the average salvage ratio at the start of each age interval or each year. The average salvage at age 2.5 years depends on the salvage during each of the preceding three age intervals. The salvage during these intervals is summed to obtain $0.11\% + 0.38\% + 0.70\%$ or 1.19% . This amount must be divided by the fraction retired by that age, or $1 - 0.8913$ or 0.1087 , to obtain $1.19\% / 0.1087$ or 10.92% . The realized salvage ratio at the start of the second age interval equals the average during the first age interval. As the age increases, the realized salvage ratio approaches the average salvage ratio. At the end of the final age interval the realized salvage ratio, 13.46%, equals the average salvage ratio.

Column (g) is the future salvage ratio, or salvage expectancy, at the start of each age interval. The future salvage ratio at any age is the average salvage ratio observers would calculate if they recorded the salvage from that time on. At age zero the future salvage ratio and the average salvage ratio are equal because both averages include all future salvage ratios. At age 6.5 years, future salvage depends on the salvage during each of the three remaining age intervals. The salvage during these intervals is summed to obtain $2.25\% + 1.04\% + 0.14\%$ or 3.43% . This amount must be divided by the future amount to be retired, which is the fraction in service at age 6.5, or 22.32% , to obtain $3.43\% / 0.2232$ or 15.37% . Because the ratios in this salvage schedule increase with age, the future salvage ratios also increase with age.

At any time, the average of the realized and future salvage ratios will equal the overall average salvage. At age 3.5 years, the weighted average of the realized and future salvage ratios is $11.40\% \times (1 - .7901) + 14.01\% \times (.7901)$ or 13.46% . Figure 4.2 (see end of chapter) is a graph of the salvage ratio, future salvage ratio, and realized salvage ratio versus age.

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Salvage Schedule Models

A survivor curve must start at 100% and decrease monotonically to zero, but there are no similar constraints for the salvage schedule. The salvage curve can be either increasing or decreasing and need not be monotonic. It need not start at 100% nor end at 0%. There are, however, several basic models that approximate actual patterns and are therefore useful to the analyst and forecaster. We will describe each first in constant dollars and then add inflation. The curve with inflation represents the salvage curve that would be constructed from observed data. The curve without inflation shows the underlying model and is therefore useful when analyzing salvage data.

The first model is a salvage ratio that, when measured in constant dollars, remains constant. This model could reflect the gross salvage of property whose major value is as scrap so that the gross salvage would equal the intrinsic value of the material. It also could be applied to the cost of retiring when the method of removal remains unchanged with time. Table 4.5 (see end of chapter) shows a salvage curve with ratios equal to 10% at all ages. The survivor curve in column (b) is an Iowa R2-5. The salvage curve is shown in column (c); all ratios are equal to 10%. Column (d) is the product of the fraction retired during the age interval and the salvage ratio shown in column (c), and when these are summed the average salvage is found to be 10%. Because the future salvage is needed when calculating depreciation, the future salvage ratios are shown in column (e).

Columns (f), (g), and (h) contain the inflated curves. The inflated ratio is found by multiplying the corresponding, uninflated ratio by the compound amount factor $(1 + i)^{age}$ where i is the inflation rate. The salvage curve for the constant model with inflation increases exponentially with age. The 6% inflation rate increases the average salvage ratio from 10% to 13.46% and the salvage ratio at the maximum life, 9 years, to 16.89%. Figure 4.3 (see end of chapter) is a graph of these salvage ratios both with and without inflation. Remember that the difference between the uninflated and inflated salvage ratios increases with age. If an example using a survivor curve with an average life longer than 5 years had been used, the difference between the two ratios would be even larger.

The second model is one in which the salvage ratio decreases uniformly with age. The linear model shown in Table 4.6 and Figure 4.4 (see end of chapter) starts at 100% at age zero (and averages 97.37% during the first age interval) and ends at 0% at age 9.5 years with a resulting annual decrease of 100%/9.5 or 10.53%. The initial value need not be 100%. Suppose, for example, that 20% of the capitalized cost was installation cost. If the property was removed immediately after installation, installation cost

would be lost and, if the full price of the unit was recovered, the salvage ratio would be 80%.

If the survivor curve is symmetrical, the average salvage ratio for the constant dollars model will be the salvage ratio at the midpoint of the curve, which here is the average of the initial and final salvage ratios. Because the survivor curve is the right modal R2 curve, more weight is given to early retirements and the average salvage is less than 50%.

The linear model with inflation also decreases, but in a nonlinear fashion. The shape of the linear model with inflation depends on slope of the line and the inflation rate. The constant model can be considered a special case of the linear model.

The third model reflects an accelerated rate early in life. This model would be particularly applicable to gross salvage when the value falls rapidly early in life and then decreases more slowly later in life. Property such as automobiles and electronic equipment are examples that might follow this pattern. Several mathematical functions could be used to describe this pattern, but a function similar to that used to calculate sum-of-years-digit depreciation was chosen.

To obtain an accelerated curve, first identify the maximum life, ML , and then sum the digits $1 + 2 + 3 + \dots + ML = (ML)(ML + 1)/2 = D$. Next find the total amount by which the salvage ratio will decrease, which is $S(0) - S(ML)$. Then find the numerator of the rate for each age interval i . For age interval 0 to 0.5 years, this is $ML/2$. For all other age intervals it is $ML - i + 0.5$. The annual decrease of salvage during age interval i is the product of the total amount of decrease times $(ML - i + .5)/D$.

Table 4.7 (see end of chapter) shows the calculation of the average salvage ratio curve using the accelerated model. The initial salvage ratio, $S(0)$, was chosen to equal 100% and the salvage ratio at the maximum life was chosen to equal zero, so that $S(ML) = 0\%$. The maximum life of the R2-5 occurs during age interval $i = 9$, or during the age interval $8.5 - 9.5$ years. The sum of digits 1 through 9 is 45. Column (b) shows the numerator of the rate, which is $L/2 = 9/2 = 4.5$ for the first interval and $9 - (i + 0.5)$ thereafter. The numerator decreases by 1 each year and the value during the final age interval is always 0.5. Each year the salvage decreases by an amount equal to the total decrease, 100%, times the weight in column (b) divided by 45. During age interval $2.5 - 3.5$ this amount is $100\% \times (9 - 3 + 0.5)/45$ or 14.44%. Because the salvage at age zero is 100%, the value at the end of the first age interval, column (c), is 100% less the decrease of $(4.5/45) \times 100\%$ or 10%, or 90%. This amount is carried forward to the start of the next age interval. The average salvage during the age interval is shown in column (f).

Table 4.8 (see end of chapter) shows the salvage ratios that would

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and the salvage shown in Table 4.7 is used; the table also shows the salvage ratios with an inflation rate of 6% applied. Figure 4.5 (see end of chapter) shows the salvage ratios without and with inflation plotted versus age.

Aged Data

Salvage curves reflecting historical salvage can be constructed from aged retirement data using the same techniques used to develop life tables. Because the forces affecting gross salvage and cost of retiring are often independent, these two costs should be recorded, analyzed, and forecasted separately. The net salvage is obtained by subtracting the cost of retiring from the gross salvage.

The requirements for aged salvage data are similar to the requirements for aged retirement data. As with aged retirement data, aged salvage data can be organized in a matrix with rows designating placement years and columns designating experience years.

Data from two sources are necessary to calculate the salvage curve for a vintage group. One set of data is the total salvage dollars during each experience year for the vintage under consideration. The salvage is either the gross salvage or the cost of retiring, depending on which salvage curve is being developed. The second set of data is the annual dollars retired during each experience year of the vintage under consideration. The salvage ratios are calculated directly from these data. The total salvage during the year depends on both the total number of retirements per year and the salvage per unit. The quotient of the total salvage divided by the original cost of the retirements equals the salvage ratio for that experience year.

The first three rows in Table 4.9 (see end of chapter) show the gross salvage, the cost of retiring, and the dollars retired from a 1982 vintage. Remember that the retirements are measured in original cost dollars (i.e., 1982 dollars), but the gross salvage and cost of retiring are measured in experience-year dollars. The ratios are the salvage dollars divided by the dollars retired for the same year. The survivor curve for this placement group shows about 22% of the property installed in 1982 is still in service at the end of 1988, so the resulting survivor curves do not reflect the complete history of the vintage group.

Conversion to Constant Dollars

An observed salvage ratio is a ratio of dollars at time x + age over dollars at time x , where x represents the year in which the property was installed. This ratio of mixed dollars often obscures underlying salvage patterns. For example, in the constant model presented in the previous section, the ratios were uniform only when measured in constant dollars,

and the shape of the inflated, or observed, curve concealed the uniform pattern. The underlying patterns are also concealed in the linear and accelerated models. Conversion of the inflated ratios to ratios of constant, or uninflated, dollars reveals the underlying model and is therefore of value to the analyst.

The examples shown in Tables 4.5 through 4.9 assumed inflation at a constant annual rate of 6%. A more accurate view would be that each year is associated with a unique inflation factor and that the product of the annual factors, rather than an average, should be used in the discounting or adjusting process.

An important question centers on which inflation factor to use. Perhaps the most common index is the consumer price index (CPI), which is familiar because it reflects changes in the weighted price of goods and services used by the typical U.S. consumer. It recognizes that different segments of the economy, (e.g., health care, food, housing, energy) have different rates of inflation and that the result is a weighted average of these.

It is desirable to obtain specialized indexes that reflect the inflation rates in special segments of the economy, and in fact firms specialize in estimating these factors. Different indexes may apply to gross salvage and cost of retiring, and the appropriate index for gross salvage in one account will generally differ from that of another account. Once the historical indexes are obtained, they can be stored in the data base and updated each year.

The matrix containing the salvage dollars can be adjusted to convert all entries to a common year or reference point. Most indexes have a base year at which the index is set to 1, and other years are measured in reference to it.

Table 4.9 contains an example of salvage data. Suppose that during the period 1982 to 1988 the annual inflation rate was 6%. Table 4.10 (see end of chapter) shows the salvage values introduced in Table 4.9 converted to 1982 dollars, so that salvage and original cost are measured at the same price level. The resulting salvage ratios now have the inflation removed. The annual salvage dollars can be converted to 1982 dollars by dividing by the factor $(1 + .06)^{age}$. In 1985 the age is 3, and the factor is $1/(1.06)^3 = 1/1.19$ or 0.840. The observed gross salvage during 1985 was \$768 and the observed cost of retiring was \$329; multiplying by 0.840 yields 1982 price level values of \$645 and \$276 respectively.

The underlying patterns can now be seen more easily. Examine the gross salvage ratio and observe that it is approximately linear and declines by about 6% each year. With inflation removed, the cost of retiring ratio is constant and equals 17%.

A first step in salvage analysis is to convert the observed dollars to constant dollars. Then the constant dollar salvage curves can be examined and fit to a model.

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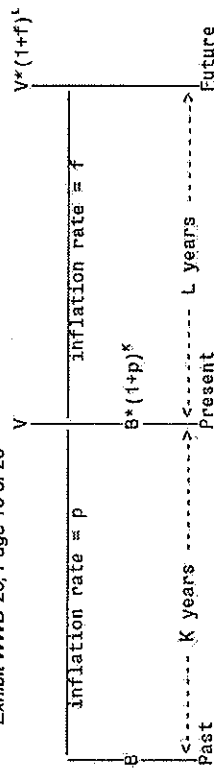


Figure 4.1. A cash flow diagram of investment and salvage costs.

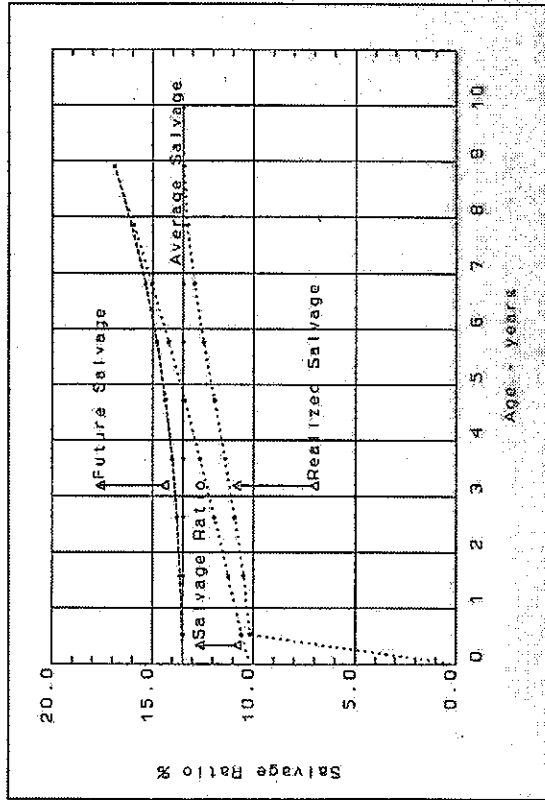


Figure 4.2. A graph of the salvage ratios and the realized and future salvage ratios versus age are for the data shown in Table 4.4.

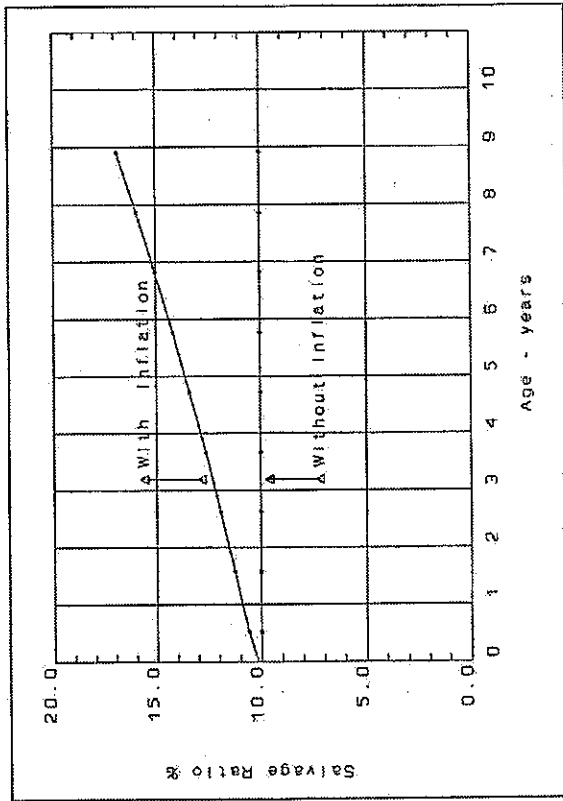


Figure 4.3. A graph of the salvage ratios shown in Table 4.5.

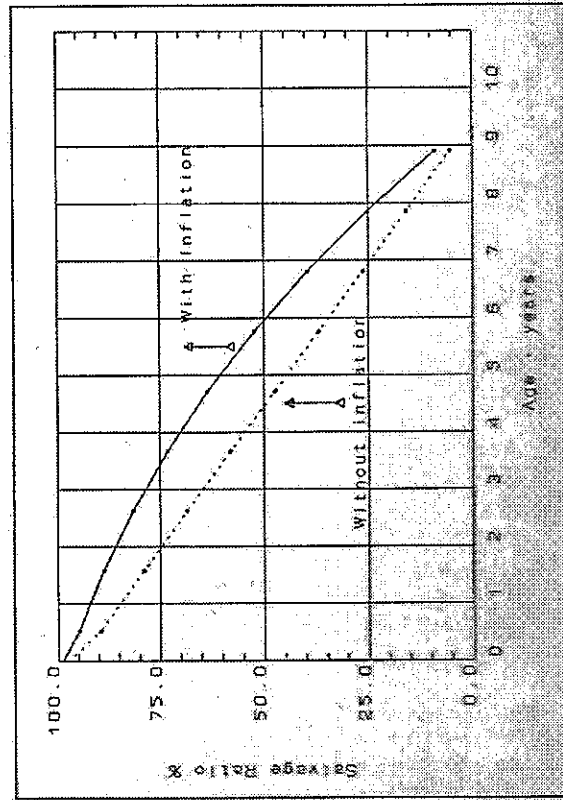


Figure 4.4. A graph of the salvage ratios shown in Table 4.6.

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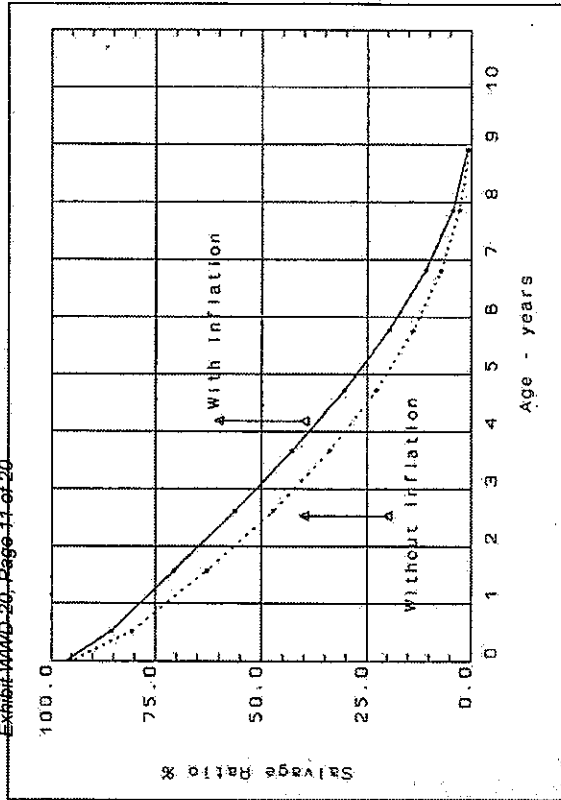


Figure 4.5. A graph of the salvage ratios shown in Table 4.8.

Table 4.2. Future salvage ratios as a function of the cost of retiring the inflation rate, j , when $p = 3\%$ of current gross salvage = 20% of first cost, and the present cost of retiring = 10% of first cost. The life of the first unit equals the life of the replacement unit.

L Years	Inflation rate - j			
	3%	6%	10%	12%
5	10.00%	8.46%	6.11%	4.80%
10	10.00%	6.67%	.70%	-3.11%
20	10.00%	2.24%	-17.25%	-33.41%
40	10.00%	-11.58%	-118.75%	-265.25%

Table 4.3. Salvage ratios as a function of life and inflation rate when $V/B = 10\%$.

Life Years	Inflation rate - p			
	3%	6%	10%	12%
0	10.00%	10.00%	10.00%	10.00%
5	11.59%	13.33%	16.11%	17.62%
10	13.44%	17.91%	25.94%	31.06%
20	18.06%	32.07%	57.27%	96.46%
40	32.62%	102.88%	452.59%	930.51%

Table 4.4. Calculation of average, realized, and future salvage ratios for the salvage schedule shown in column (d) and with life characteristics described by an Iowa 82-5 survivor curve. The percent surviving, realized salvage ratio, and future salvage ratio are all shown at the start of the age interval.

Age Interval (h)	Constant rate w/inflation						
	Percent survive (b)	Percent retired (c)	Salvage ratio % (d)	Weighted ratio % (e)	Realized salvage % (f)	Future salvage % (g)	Average % (h)
0-0.5	100.00	1.11	10.15	.11	.00	13.46	13.46
0.5-1.5	98.89	3.58	10.50	.38	10.15	13.50	13.46
1.5-2.5	95.33	6.20	11.24	.70	10.49	13.61	13.46
2.5-3.5	89.13	10.12	11.91	1.21	10.92	13.77	13.46
3.5-4.5	79.01	15.31	12.62	1.93	11.40	14.01	13.46
4.5-5.5	63.70	20.30	13.38	2.72	11.91	14.34	13.46
5.5-6.5	43.40	24.08	14.19	2.98	12.44	14.79	13.46
6.5-7.5	23.32	27.03	15.04	2.25	12.91	15.37	13.46
7.5-8.5	7.83	31.81	15.94	1.04	13.26	16.05	13.46
8.5-9.5	.82	36.02	16.89	.44	13.43	16.89	13.46
9.5-10.0	.00				13.46		13.46
				Average =	13.46%		

Table 4.1. Future salvage ratios as a function of the future inflation rate, f , and the life of the unit, K . The salvage ratio of the first unit is $V/B = 10\%$ and p , the annual rate of inflation during its life, is 3%. The life of the first unit, equals the life of the replacement unit (i.e., $K = L$).

K Years	Inflation rate - f			
	3%	6%	10%	12%
5	10.00%	11.58%	13.08%	15.20%
10	10.00%	13.33%	19.80%	23.11%
20	10.00%	17.91%	37.88%	53.41%
40	10.00%	31.88%	101.70%	205.28%

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Table 4.5. A salvage curve with a constant rate and 6% inflation.

Age Interval (a)	Percent survive (b)	Salvage ratio % (c)	Weighted ratio % (d)	Constant rate	Future salvage ratio % (e)	Salvage ratio % (f)	Weighted ratio % (g)	Future salvage ratio % (h)
0-0.5	100.00	10.00	.11	* Constant rate w/inflation *	10.00	10.15	.11	13.46
1.5-1.5	98.89	10.00	.36		10.00	10.60	.38	13.61
2.5-2.5	95.33	10.00	.62		10.00	11.24	.70	13.61
3.5-3.5	89.13	10.00	1.01		10.00	12.08	1.21	13.77
4.5-4.5	79.01	10.00	1.53		10.00	13.18	1.93	14.01
5.5-5.5	63.70	10.00	2.93		10.00	14.58	2.72	14.24
6.5-6.5	43.40	10.00	2.11		10.00	16.29	2.99	14.57
7.5-7.5	22.32	10.00	1.59		10.00	18.34	2.25	15.07
8.5-8.5	7.82	10.00	.82		10.00	20.76	1.04	16.05
9.5-10.5	.00	---	.00		10.00	23.56	.14	16.89
		Average = 10.00%				Average = 13.48%		

Table 4.6. A linear salvage curve starting at 100% and declining to 0%, with 6% inflation.

Age Interval (a)	Percent survive (b)	Salvage ratio % (c)	Weighted ratio % (d)	Linear rate	Future salvage ratio % (e)	Salvage ratio % (f)	Weighted ratio % (g)	Future salvage ratio % (h)
0-0.5	100.00	97.37	1.08	* Linear rate w/inflation *	47.35	98.80	1.10	60.94
1.5-1.5	98.89	89.47	3.19		46.79	94.84	3.38	60.51
2.5-2.5	95.33	78.95	4.89		45.19	88.71	5.50	59.23
3.5-3.5	89.13	68.42	6.92		42.84	81.49	8.25	57.18
4.5-4.5	79.01	57.89	8.85		39.57	73.09	11.19	54.07
5.5-5.5	63.70	47.37	9.62		35.16	63.39	12.87	49.49
6.5-6.5	43.40	36.84	7.77		29.45	52.26	11.02	42.49
7.5-7.5	22.32	26.32	3.94		22.47	39.57	5.93	34.24
8.5-8.5	7.82	15.79	1.83		14.61	25.17	1.64	23.35
9.5-10.5	.00	---	.00		5.26	8.69	.07	8.89
		Average = 47.35%				Average = 60.94%		

Table 4.7. Calculation of an accelerated salvage curve starting at 100% and declining to 0%.

Age interval (a)	Weight (b)	Change (c)	Salvage at start (d)	Salvage at end (e)	Average salvage (f)
0-0.5	4.5	10.00	100.00	90.00	95.00
1.5-1.5	8.5	18.89	80.00	71.11	80.55
2.5-2.5	7.5	16.07	60.00	54.44	62.78
3.5-3.5	6.5	11.94	40.00	40.00	47.23
4.5-4.5	5.5	7.29	20.00	27.78	33.89
5.5-5.5	4.5	3.11	10.00	17.78	24.28
6.5-6.5	3.5	0.83	5.00	10.00	13.39
7.5-7.5	2.5	0.31	2.50	5.00	7.21
8.5-8.5	1.5	0.11	1.25	2.50	3.88
9.5-10.5	0.5	0.03	0.63	1.25	1.94

Table 4.8. A salvage curve with the accelerated model shown in Table 4.7 and with 6% inflation.

Age Interval (a)	Percent survive (b)	Salvage ratio % (c)	Weighted ratio % (d)	Accelerated rate	Future salvage ratio % (e)	Salvage ratio % (f)	Weighted ratio % (g)	Future salvage ratio % (h)
0-0.5	100.00	95.00	1.05	* Accelerated rate w/inflation *	26.60	96.39	1.07	32.99
1.5-1.5	96.89	80.56	2.87		25.83	85.39	3.04	32.28
2.5-2.5	95.33	62.78	3.89		23.79	70.54	4.37	30.29
3.5-3.5	89.13	47.22	4.78		21.08	56.24	5.89	27.50
4.5-4.5	79.01	33.89	5.19		17.73	42.78	6.55	23.61
5.5-5.5	63.70	22.78	4.62		13.85	30.48	6.19	19.25
6.5-6.5	43.40	13.89	2.93		9.67	19.70	4.15	14.00
7.5-7.5	22.32	7.22	1.98		5.68	10.85	1.63	8.62
8.5-8.5	7.82	2.78	.82		2.53	4.43	.29	4.04
9.5-10.5	.00	---	.00		---	.94	.01	---
		Average = 26.60%				Average = 32.99%		

Table 4.9. Partial retirement and salvage data from the 1982 vintage group. The upper portion of the table shows the gross salvage dollars, the cost of retiring, and dollars retired for a vintage group. The lower portion of the table shows the resulting salvage ratios.

	82	83	84	85	86	87	88
Gross salvage	94	857	470	768	1053	1191	1021
Cost of retiring	27	113	183	329	552	721	784
Annual retirements	157	827	941	1568	2508	3135	8292
Gross salvage ratio	.60	.57	.50	.49	.42	.38	.31
Cost of retiring ratio	.17	.18	.20	.21	.22	.23	.24
Net salvage ratio	.43	.39	.30	.28	.20	.15	.07

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 Table 4.10. Conversion of salvage in Table 4.9 to 1982 dollars.

	Experience year						
	82	83	84	85	86	87	88
Gross salvage	94	337	418	645	834	890	720
Cost of retiring	27	106	163	276	437	539	553
Annual retirements	157	627	941	1568	2508	3135	3292
Gross salvage ratio	.60	.54	.44	.41	.33	.28	.22
Cost of retiring ratio	.17	.17	.17	.18	.17	.17	.17
Net salvage ratio	.43	.37	.27	.23	.16	.11	.06

5

Depreciation Systems

THE recovery of capital through depreciation accruals may be thought of as a dynamic system. A system is an arrangement of things that are connected to form a complete organization of integrated parts. The state of the system at any time is defined by current values of the characteristics that define the system. A dynamic system is one where the state of the system depends on the history of the input variables. To define and study a system is to better understand the system so that more efficient methods of control can be designed to accomplish the desired ends.

There are two methods of controlling a system. One is to select an input and wait for the result or final output. If a different output is desired, the input is changed and the new output is obtained. The other method of control is to select an initial input, monitor the process, and when necessary, alter the input to achieve the desired goal. The first method is called an open control loop and the second a closed control loop. A necessary feature of the closed control loop is the feedback resulting from the monitoring of the system. A home heating system is a common and simple example of a dynamic system with a closed feedback loop. The parts of the system are a furnace and a thermostat. The thermostat monitors the room temperature and creates feedback, in the form of electrical signals, when the room temperature rises above or falls below the desired temperature. The electrical signals turn the furnace off or on to achieve the desired goal, a constant, predetermined room temperature.

Think of a depreciation accounting system as a dynamic system controlled with a closed feedback loop. Estimates of life and salvage and the

14 Salvage Analysis and Forecasting

THIS chapter discusses the analysis of aged salvage data and illustrates the use of a mathematical model to help estimate future salvage. Table 8.1 at the end of Chapter 8 shows the aged retirements for Account 897, Utility Devices. These data will be needed in this chapter. For convenience, Table 8.1 will be called the *retirement matrix*.

Net salvage is composed of gross salvage and cost of retiring.¹ Data reflecting these two categories often are kept separately. Different economic forces act on each, so that the pattern of gross salvage versus age differs from the pattern of cost of retiring versus age. If separate records are kept, each pattern can be analyzed. If the records are combined, the separate patterns may be obscured.

Though the patterns of gross salvage and cost of retiring versus age may be different, the general process for analyzing the patterns is the same. The gross salvage for Utility Devices will be assumed to be zero. This will simplify our illustration, and the cost of retiring will provide an example on which to base a discussion of analyzing and forecasting salvage.

Table 14.1 (see end of chapter) shows the cost of retiring by age for Account 897. Each row represents a vintage (or placement or installation) year, and each column represents an experience (or calendar) year. Each entry in the table is the total cost of retiring units from that vintage during that experience year. Vintage years run from 1962 through 1990 and experience years from 1968 through 1990.

Table 14.2 (see end of chapter) shows the salvage ratios (SR) for Account 897. The SR is the salvage divided by the original cost of the retirements and usually is expressed as a percentage. During 1974, \$9.00 from the 1971 vintage was retired (see the retirement matrix). The cost of retiring these dollars, shown in Table 14.1, was \$2.03, and the resulting SR is $-2.03/9.00$ or -22.6% .

SALVAGE ANALYSIS

Salvage analysis starts with an examination of the data reflecting the total annual costs. Often these are the only data available. The final row in Table 14.1 shows the sum of each column and equals the total cost of retiring during the calendar year. The original cost of all retirements during the calendar year is shown in the retirement matrix. Table 14.3 (see end of chapter) combines these annual retirement amounts. Column (a) shows the calendar year, column (b) shows the total dollars retired during the year, and column (c) shows the total cost of retiring during the year. Column (d) is the salvage ratio (SR) for the year (i.e., column (c)/column (b) times 100%). Statistics based on single years are often erratic, making any underlying pattern difficult to detect. The final four columns are used in the calculation of SRs for 3-year "rolling bands" or moving averages. This averaging process smooths the pattern of ratios. Column (e) defines the rolling bands. Each band has 2 years in common with the bands on either side of it. The retirements, column (f), during the 1968-1970 band equal $18.00 + 30.00 + 42.00$ or \$90.00, and the cost of retiring, column (g), is $(-4.28) + (-7.65) + (-10.42)$ or -22.35 . Column (h) is the average SR during the 3-year rolling band.

The average realized salvage is the total cost of retiring divided by the total retirements, or $-1452.28/3833.00$ or -37.9% . The SRs steadily become more negative, from about -24% during the early years to about -40% during the most recent years. One reason for this trend is that the average age of the annual retirements has increased. The first additions were made in 1962. The average life of the property in Account 897 is known to be about 10 years. During 1969 the account was "young," because a retired unit could not have been older than 7 years (i.e., a retirement from the 1962 vintage), and most retirements were younger than 7 years (i.e., retirements from more recent vintages). The average age of the units retired during 1969 was 4.8 years (the age and number of dollars retired during 1969 can be found in the retirement matrix). As time passed, the average age of the retirements increased. By 1989 the average age of retirements was 10.2 years.

In a stable account with zero growth (see Chapter 9), the average age of the retirements equal the average life. Though the annual additions to

Account 897 vary from year to year, the net growth in the account is near zero. By 1989 the account is "mature." The oldest vintage was installed more than 25 years ago, so the age of retirements can range from less than a year to the maximum life. Thus, the average age of the retirements during 1989 would be expected to be near the average life, and they are. If no more additions were made to the account, the average age of retirements would increase with time, and, as the plant remaining in service becomes less and less, the average age of the retirements will increase and approach the maximum life. The sum of all future costs of retiring divided by the sum of future retirements (i.e., the current balance) is the future salvage ratio (FSR). The average salvage ratio (ASR) is the sum of the realized cost and the future cost of retiring, divided by the original cost of all additions.

The data in Table 14.3 show that the cost of retiring increases with the age of the retired unit. Though the average cost of retiring all units retired to date is known, the future cost of retiring must be estimated before the ASR can be estimated. Without additional data or adoption of a retirement model, it is difficult to describe how to estimate the future cost of retiring.

Before attempting to forecast the future cost of retiring, the depreciation professional should become familiar with the physical characteristics of the property in the account and with the manner of retiring the property from service. This knowledge will provide the basis for developing a preliminary model describing the relationship between age and salvage. One cost of retiring model is based on the observation that the cost of retiring a unit is often independent of the age of the unit. For example, the process of removing a gas service or a utility pole typically has little to do with the age of the service or pole. This model can be extended by assuming that the process of retiring the unit is labor intensive, and that the hours of labor required to retire a unit have remained constant during the history of the account. This implies the technology used to retire a unit has remained constant.

This model will be adopted and applied to Account 897. Remember that this is one of many possible models, and the depreciation professional cannot adopt a model unless he or she is familiar with the property involved and the company operations that affect the method of retirement. The logic of the mathematical model must reflect the actual world. Whether the model reflects reality is a judgment made by the analyst.

If the model just described reflects the cost of retiring a utility device, then, during periods of inflation, the SRs can be expected to increase as a unit becomes older. Though the hours of labor required to retire the unit remain constant, labor rates can be expected to inflate each year. Thus, the SR for a group of property installed during the same year can be expected to increase (i.e., become more negative) each successive year in direct proportion to the annual rate of inflation. A more comprehensive analysis of

the aged data will reveal the historical relationship between age and salvage ratio and may provide support for the model. Chapter 8 introduced the idea of placement bands and experience bands. A placement band follows the history of a vintage through different experience years, while an experience band follows the history over all vintages during the specified experience years.

These ideas are used to construct a graph of the SR versus age for the placement band consisting of the 1970, 1971, and 1972 vintages. Table 14.4 (see end of chapter) reproduces part of the annual cost of retiring during 1970, 1971, and 1972 from Table 14.1. The cost of retiring is shown in the upper portion of Table 14.4.

Table 14.5 (see end of chapter) shows how the data are used to construct salvage ratios by age. Column (a) of Table 14.5 shows the age interval and column (b) shows the sum of retirements from the 1970, 1971, and 1972 vintages during each age interval. Column (c) shows the corresponding cost of retiring. To obtain the total cost of retiring during the 0.0-0.5 year age interval, refer to the upper portion of Table 14.4. Sum the first entry in each row, $0 + 0 + (-1.02)$ or -1.02 . These are the costs of retiring during 1970 from the 1970 vintage, during 1971 from the 1971 vintage, and during 1972 from the 1972 vintage, respectively. Column (d) is the SR, or the cost of retiring divided by the original cost expressed as a percentage. Observe that the SR during the initial age interval is about -20% , and that the SRs steadily become more negative as the property ages. After 20 years, the SR is almost -70% . Because these figures represent costs, the costs increase but the SRs decrease (become more negative).

Because the SR is the quotient of dollars in different price levels (i.e., the retirement year price level is reflected in the numerator and the installation year price level is reflected in the denominator), it may be helpful to calculate the SR using a constant price level. This removes inflation from the ratio so that the salvage schedule adjusted for inflation² can be analyzed.

To calculate the adjusted SR shown in column (f) of Table 14.5, return to Table 14.4 and note the row labeled CPI-U. These data are the July consumer price indexes for all urban consumers (CPI-U) from the U.S. Bureau of Labor Statistics for the years 1970 through 1977. The July figures were chosen because both additions and retirements are assumed to take place at midyear. During 1975, the cost of retiring units placed in service during 1971 totaled $-\$1.49$. To adjust 1975 dollars to 1971 dollars, multiply the 1975 dollars by the ratio of the 1971 index/1975 index. This is $-1.49 \times (40.70/54.20)$ or $-\$1.12$ measured in July 1971 dollars. The lower portion of the table shows the salvage from the upper portion of the table after being adjusted to dollars during the placement year. The adjusted cost of retiring can now be used to calculate the adjusted cost of

retiring shown in column (e) of Table 14.5. The original cost of the retirements shown in column (b) and the salvage shown in column (e) are measured in dollars of the same price level. Column (f) shows the adjusted SR, i.e., column (e)/column (b) \times 100%.

Figure 14.1 is a graph of columns (d) and (f). Observe the graph of the SRs with inflation. If the SRs are increasing in proportion to inflation, they will form a pattern that is curved upward, reflecting the exponential growth of the price levels. However, it is difficult to tell the underlying shape of this curve. Observe the graph of the SRs when inflation is removed. The pattern of constant SRs, with a value of about -20%, is clear. Though a formal statistical test of the relationship can be made, such a test is not necessary because the graph is strong evidence that when inflation is removed, the cost of retiring is independent of age. Thus, the data supports, or verifies, the model that the time required to retire a unit is constant and that the increased cost of retiring is proportional to the rate of inflation.

Can this model be used to forecast future cost of retiring? If the depreciation professional believes that the same procedure for retiring that has been used in the past will continue to be used in the future, then the model can be used to forecast future cost of retiring. Under this model, future SRs

can be derived if three parameters are estimated. They are (a) the SR during the 0.0-0.5 year age interval, (b) the annual rate of inflation, and (c) the life characteristics of the property.

Table 14.6 (see end of chapter) shows the construction of the salvage schedule for the 1981 vintage. Construction of the survivor curve for this vintage is shown in Table 6.12 of Chapter 6, and the survivor curve from that table is shown in column (b) of Table 14.6. The values from age 0.0-8.5 years are based on the observed exposures and retirements. The values from age 8.5-21.5 years are based on the estimate that the future life characteristics will be described by an Iowa S0-12 survivor curve. The SRs, column (d), from age 0.0-8.5 years are the observed values shown in Table 14.2. The forecast for all age intervals beyond 8.5 years is the SR from the previous age interval inflated by 5% (i.e., the SR during age interval 9.5-10.5 is 29.72×1.05 or 31.20%). The 5% rate is the estimate of the future inflation rate. Column (e) is the SR weighted by the fraction retired, i.e., column (c) \times column (d)/100%, and the sum of column (e) is the ASR, -34.81%. The realized salvage ratio is shown in column (f) and the future salvage ratio (FSR) is shown in column (g). Because the observed SRs were used during the early age intervals, it was not necessary to estimate the initial SR.

THE BROAD AND VINTAGE GROUP MODELS

Depreciation calculations require an estimate of the average salvage ratio (ASR) and the future salvage ratio (FSR) for each vintage. The method of determining these ratios depends on whether the broad group or vintage group model is used.

If the broad group model is used, the same salvage schedule is applied to each vintage. Chapter 6 contains an illustration of the application of a single salvage schedule to each vintage. Table 6.11 of that chapter is a salvage schedule used in the calculation of the annual accrual using both the AL and ELG procedures. The salvage ratio during the 0.0-0.5 year age interval is -15%, and it increases (becomes more negative) at an annual rate of 5%. These ratios are used with the ELG procedure. The Iowa S0-12 curve describes the life characteristics of each vintage. The resulting ASR, -28%, is used with the AL procedure. The FSR at the start of each age interval is matched to the appropriate vintage. Depending on the depreciation system, the CAD of the future accrual is then calculated using the proper FSR. Thus, a single salvage schedule provides the information to calculate the annual accrual for each vintage.

If the vintage group model is applied to salvage, a different salvage schedule is applied to each vintage. The calculation of the schedule for the 1981 vintage is shown in Table 14.6. It results in the ASR and the FSR for

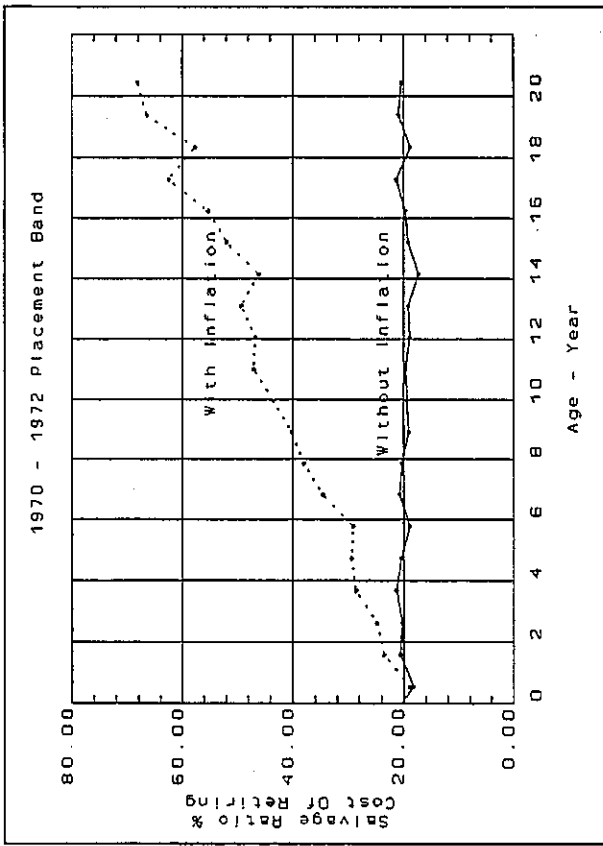


Figure 14.1. Salvage ratios versus age both with and without inflation. Data are from Table 14.3.

the 1981 vintage, and similar calculations must be made for all other vintages. The vintage group model, which uses observed life and observed salvage data to construct the realized portion of the schedule, is a refinement of the broad group model. It has the advantage of more accurately reflecting the actual world transactions than does the broad group model.

THE SIMULATION OF SALVAGE BY AGE

It is not uncommon to record only the total salvage during the year. The data shown in Table 14.3 are of this type. Estimates of the ASR and an average FSR must be based on the unaged salvage data. When retirements are recorded by age, an alternate method of using this data is available. The alternative requires the depreciation professional to adopt a salvage model and use it to allocate the total annual salvage to each vintage. The result is salvage by age, as shown in Table 14.1, except the data are simulated rather than observed. The simulated data can be used in the manner described earlier in this chapter. However, the simulated data cannot be used to verify the model because to do so would be circular logic.

Table 14.7 (see end of chapter) shows how the \$10.42 cost of retiring during 1970 can be allocated to the 1962 through 1970 vintages if the cost of retiring model discussed earlier in this chapter is adopted. The depreciation professional must be familiar with the account Utility Devices so that he or she can judge whether the model will result in a reasonable representation of the cost of retiring. Column (a) shows the vintage year and column (b) shows the original cost of the retirements during the 1970 calendar year. Column (c) shows the consumer price index (CPI-U) for July of the vintage year. Column (d) shows the ratio of the CPI-U for the vintage year to the CPI-U for the 1970 calendar year. For 1963, the ratio $61.0/39.0$ or 1.56 suggests that a dollar spent in 1963 would purchase 1.56 times as much as a dollar spent in 1970. Column (e) is the product of column (b) times column (d), and represents a restatement of the vintage dollars to 1970 price level dollars. The \$14.00 retired in 1963 are restated as \$21.90 in the 1970 price level.

Thus, entries in column (e) are proportional to the units retired during 1970 if the model is applicable and the CPI-U is an appropriate index. The entries in column (e) are used as weights to allocate the \$10.42 cost of retiring. Column (f) is the entry from column (e) divided by the sum of column (e). The fraction of the \$10.42 allocated to the 1963 vintage is $21.90/61.84$ or 0.3541 . The allocation to the 1962 vintage is 0.3541×10.42 or \$3.69, as shown in column (g). If this process is repeated for each calendar year, the result is the simulated cost of retiring by age. The simulated data can be used to construct salvage schedules similar to the schedule shown in Table 14.5.

SUMMARY

It is desirable to analyze gross salvage and cost of retiring separately. The two salvage schedules can be combined to find the average net salvage ratio and the future net salvage ratios by age. Data that reflect salvage by age, rather than only the total annual salvage, provide valuable information.

In practice, the procedure for estimating salvage varies widely. The depreciation professional's judgment of whether a procedure is reasonable is based on several variables. These include the magnitude of the salvage ratio, the available data, and the importance of the depreciable group. It is not unusual for a mass property account of a utility to exhibit large negative salvage. In such cases, the depreciation accrual rate may be more sensitive to the salvage estimate than to the life estimate.

If both the realized gross salvage and realized cost of retiring are near zero, extensive analyses may not be productive because the depreciation calculations are not sensitive to salvage ratios near zero. In such cases, the key to forecasting is predicting whether there will be a significant change in future operations that will change the levels of gross salvage or cost of retiring.

Often the only available data are the total annual gross salvage and cost of retiring. An example of this type of data is shown in Table 14.3. When analyzing unaged salvage, remember that realized salvage depends on the age of the retirements. Realized salvage starts at zero and does not reach the average until the final unit in the group is retired. Thus, the average age of the annual retirements and the average life of the group are important variables. Continuous property groups showing growth typically have large differences between the average age of the retirements and the average life of the group.

Salvage ratios are a function of inflation. For long-lived property, the salvage associated with the longest-lived property is affected most. However, this effect may not be reflected in the data for some time. A mathematical model that includes the effect of salvage can be a valuable forecasting tool. Salvage data by age contains information helpful for constructing and verifying a mathematical model.

NOTES

1. Cost of retiring is also called cost of removal.
2. See Chapter 4 for a discussion of inflation and salvage ratios.

DEPRECIATION SYSTEMS

Table 14.1 The cost of retiring by age for Account 897.

Calendar Year	Account 897 -												
	68	69	70	71	72	73	74	75	76	77	Cost of		
1962	1.92	1.87	3.21	.72	2.42	2.77	5.04	.87	.00	.00	.00		
1963	.00	.89	3.17	1.84	2.75	2.51	5.34	4.37	5.06	9.89			
1964	.66	.80	1.00	1.94	1.06	2.35	2.99	6.77	18.36	15.80			
1965	.00	1.84	1.00	2.93	2.21	2.66	2.74	1.76	1.40	.00			
1966	1.71	1.96	1.78	2.88	4.88	3.20	4.68	11.57	5.82	.77			
1967	.00	.44	.89	3.26	3.70	8.84	4.14	6.40	6.67	2.99			
1968	.00	.00	.40	.50	.00	.89	.95	1.58	1.76	2.33			
1969	.00	.00	.00	2.25	.00	.00	.00	.00	.56	.00			
1970	.00	.00	.00	.20	.19	1.58	.80	.81	.88	2.48			
1971	.00	.00	.00	.00	.71	.63	2.03	1.49	1.57	2.79			
1972	.00	.00	.00	.00	1.02	.41	1.30	2.00	3.13	7.03			
1973	.00	.00	.00	.00	.00	1.72	.00	.00	.00	2.11			
1974	.00	.00	.00	.00	.00	.00	.00	.22	.73	1.86			
1975	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1976	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1977	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1978	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1979	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1980	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1981	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1982	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1983	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1984	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1985	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1986	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1987	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1988	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1989	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			
1990	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00			

Total 4.28 7.65 10.42 16.51 18.93 27.57 30.02 38.67 45.94 52.48

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Utility Devices
 Retiring

Year	78	79	80	81	82	83	84	85	86	87	88	89	90
1962	.00	2.51	3.96	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1963	2.29	4.13	4.63	4.00	3.16	3.07	4.09	.00	.00	.00	.00	.00	.00
1964	11.02	1.33	2.12	13.34	5.10	3.61	.00	.00	.00	.00	.00	.00	.00
1965	2.40	3.15	3.08	26.85	2.27	1.23	1.70	12.56	3.94	9.68	.00	.00	.00
1966	14.60	2.59	2.50	12.68	4.68	8.78	6.71	5.44	.00	.00	.00	.00	12.45
1967	2.64	10.61	2.46	4.79	19.23	6.67	6.79	8.46	4.55	.00	10.78	.00	.00
1968	2.24	2.50	7.55	.00	.00	.00	7.25	.00	.00	.00	.00	.00	.00
1969	10.12	.00	3.64	3.15	1.93	2.81	2.90	1.70	3.83	2.39	.00	.00	2.13
1970	3.19	2.35	2.95	5.85	4.87	4.27	4.92	.00	8.62	15.47	9.09	11.60	8.18
1971	7.97	6.78	7.29	9.98	4.44	20.88	4.34	6.09	.00	4.20	5.40	5.38	6.88
1972	11.54	7.09	5.86	3.41	15.67	10.23	9.82	24.77	10.88	16.94	.00	.00	6.73
1973	.56	2.48	2.01	2.88	4.97	4.59	3.20	2.80	1.37	3.44	4.86	5.19	2.29
1974	.00	.00	1.54	2.00	9.31	8.48	5.52	3.94	2.52	1.78	3.73	3.61	.00
1975	1.65	10.88	8.86	20.24	7.16	27.59	9.78	7.55	23.88	10.28	8.16	5.71	5.34
1976	.00	.99	1.10	.85	2.13	4.16	3.82	6.49	20.16	24.95	23.93	7.00	.00
1977	.00	.00	.00	2.02	.00	5.39	.00	26.01	7.82	9.10	8.52	7.06	.00
1978	.00	.64	.00	.00	.00	1.91	5.92	8.76	5.96	11.44	9.95	8.95	4.38
1979	.00	.00	.00	.00	.00	.95	.90	.66	4.96	11.11	9.96	9.82	1.89
1980	.00	.00	.00	.00	.00	.45	.00	.00	1.38	2.57	2.39	3.11	.00
1981	.00	.00	.00	1.22	1.05	.00	.00	.00	1.48	1.44	1.81	2.67	2.40
1982	.00	.00	.00	.00	.00	.00	.00	.46	.92	1.24	1.84	2.30	.27
1983	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1984	.00	.00	.00	.00	.00	.00	.00	2.18	.00	1.48	2.28	3.66	.00
1985	.00	.00	.00	.00	.00	.00	.00	.75	.00	.00	.00	.00	.00
1986	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1987	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1988	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1989	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1990	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00

Total 71.96 61.65 69.89 117.16 81.97 116.39 77.04 140.41 103.17 124.50 102.63 89.68 53.38

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Table 14.3. Salvage ratios by calendar year for Account 897, Utility Devices. Column (d) is the SR for a single year and column (h) is the average SR for 3-year rolling bands.

Year (a)	Dollars retired (b)	Cost of retiring (c)	SR % (d)	Years (e)	Dollars Retired (f)	Cost of retiring (g)	SR % (h)
1968	18.00	-4.28	23.8	1968-70	90.00	-22.35	24.8
1969	30.00	-7.85	25.5	1969-71	140.00	-34.57	24.7
1970	42.00	-10.42	24.8	1970-72	186.00	-45.38	24.7
1971	68.00	-16.51	24.3	1971-73	252.00	-63.01	25.0
1972	76.00	-18.93	24.9	1972-74	281.00	-76.51	27.2
1973	108.00	-27.57	25.5	1973-75	320.00	-86.25	30.1
1974	97.00	-30.02	30.9	1974-76	350.00	-114.62	32.7
1975	115.00	-38.67	33.6	1975-77	415.00	-137.08	33.0
1976	138.00	-45.94	33.3	1976-78	510.00	-170.98	33.4
1977	162.00	-52.48	32.4	1977-79	535.00	-186.08	34.3
1978	163.00	-71.86	32.4	1978-80	524.00	-182.08	36.9
1979	151.00	-81.65	39.7	1979-81	574.00	-208.69	41.6
1980	151.00	-59.89	39.7	1980-82	697.00	-239.01	43.4
1981	260.00	-117.16	45.1	1981-83	733.00	-215.51	49.0
1982	188.00	-81.97	43.6	1982-84	844.00	-275.40	42.8
1983	287.00	-115.99	40.6	1983-85	834.00	-333.84	40.0
1984	171.00	-77.04	45.3	1984-86	808.00	-320.62	39.8
1985	376.00	-140.41	37.3	1985-87	843.00	-368.09	39.0
1986	259.00	-103.17	39.8	1986-88	825.00	-330.31	40.1
1987	308.00	-124.50	40.4	1987-89	814.00	-316.81	38.9
1988	268.00	-102.53	40.1	1988-90	688.00	-245.69	40.4
1989	260.00	-89.88	35.3				
1990	102.00	-53.38	52.3				
Total	3863.00	-1452.28	37.9				

Table 14.4. Aged cost of retiring for the 1970 through 1972 vintage, as extracted from Table 14.1. The lower portion of the table adjusts the annual cost of retiring to the price level during the year the property was installed using the consumer price index for all urban consumers (CPI-U) from the U.S. Bureau of Labor Statistics, 1982=1984 = 100.

Year	70	71	72	73	74	75	76	77	78
1970	.00	.20	.19	-1.58	-2.03	1.81	.88	-2.48	-1.73
1971	.00	.00	.71	-1.63	-2.03	-1.49	-1.57	-2.79	-4.19
1972			-1.02	-1.41	-1.30	-2.88	-3.13	-7.03	-7.97
CPI-U	39.00	40.70	41.90	44.30	49.40	54.20	57.10	61.00	65.70
1970	.00	.19	.18	-1.39	-1.63	.59	.60	-1.58	-1.03
1971	.00	.00	.69	-1.58	-1.67	-1.12	-1.12	-1.89	-1.89
1972			-1.02	-1.39	-1.10	-2.16	-2.30	-4.83	-5.08

Account 897 - Utility Devices
 Salvage Ratios ** All Ratios Are Negative

Calendar Year	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	
Calendar Year	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	
Salvage Ratio	23.9	23.0	22.2	22.0	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	
...

Table 14.5. The salvage ratio schedule for the 1970-1992 placement band. The non-adjusted retirement cost is measured in dollars during the year of retirement. The adjusted retirement cost is measured in dollars during the year of installation.

Age Interval (a)	Dollars retired (b)	Non-adj cost of retiring (c)	Non-adj SR (d)	Adjusted cost of retiring (e)	Adjusted SR (f)
0-0.5	5.00	-1.02	-20.3	-1.02	-20.3
0.5-1.5	7.00	-1.32	-19.9	-1.27	-18.2
1.5-2.5	9.00	-2.12	-23.5	-1.86	-20.6
2.5-3.5	26.00	-6.44	-24.8	-5.25	-20.2
3.5-4.5	19.00	-5.43	-28.6	-4.05	-21.3
4.5-5.5	32.00	-9.41	-29.4	-6.53	-20.4
5.5-6.5	40.00	-11.63	-29.1	-7.54	-18.9
6.5-7.5	38.00	-12.45	-34.6	-7.45	-20.7
7.5-8.5	35.00	-13.28	-38.0	-7.27	-19.1
8.5-9.5	38.00	-15.28	-40.2	-6.22	-19.4
9.5-10.5	32.00	-13.93	-43.5	-10.46	-19.7
10.5-11.5	53.00	-24.90	-47.0	-4.34	-18.9
11.5-12.5	23.00	-10.74	-49.3	-5.39	-19.2
12.5-13.5	28.00	-13.61	-46.1	-8.85	-17.3
13.5-14.5	5.00	-2.30	-46.1	-5.37	-19.2
14.5-15.5	28.00	-14.52	-55.3	-8.09	-19.7
15.5-16.5	41.00	-22.65	-55.3	-6.78	-21.3
16.5-17.5	27.00	-16.85	-57.7	-6.00	-18.8
17.5-18.5	32.00	-18.47	-57.7	-6.93	-20.9
18.5-19.5	4.00	-2.65	-66.5	-2.45	-20.4
19.5-20.5	12.00	-5.18	-68.2		

Table 14.6. The salvage schedule for the 1981 vintage. Observed values are used through age 8.5 years. The future survivor curve is an Iowa 90-12 curve. Future salvage ratios are found by inflating the SR from the previous year by 5%.

Age Interval (a)	Percent surviving (b)	Percent retired (c)	SR % (d)	Wtd SR (e)	Realized SR% (f)	Future SR% (g)
0.0-0.5	100.00	0.17	-20.40	-65	.00	-34.81
0.5-1.5	96.83	1.00	-22.40	.00	-20.40	-35.29
1.5-2.5	93.77	2.12	-23.00	-.24	-20.40	-35.43
2.5-3.5	90.65	3.39	-23.28	-.37	-21.27	-35.73
3.5-4.5	87.56	4.71	-23.70	-.52	-21.65	-35.95
4.5-5.5	84.50	6.08	-24.00	-.68	-22.81	-36.82
5.5-6.5	81.48	7.50	-24.30	-.85	-24.03	-36.93
6.5-7.5	78.50	8.96	-24.60	-1.00	-24.99	-37.45
7.5-8.5	75.57	10.46	-24.90	-1.17	-19.60	-40.44
8.5-9.5	72.69	12.00	-25.20	-1.35	-21.38	-41.36
9.5-10.5	69.86	13.58	-25.50	-1.54	-22.89	-42.34
10.5-11.5	67.07	15.20	-25.80	-1.74	-24.22	-43.38
11.5-12.5	64.32	16.86	-26.10	-1.94	-25.43	-44.48
12.5-13.5	61.61	18.56	-26.40	-2.15	-26.57	-45.65
13.5-14.5	58.94	20.30	-26.70	-2.36	-27.64	-46.88
14.5-15.5	56.31	22.08	-27.00	-2.58	-28.67	-48.17
15.5-16.5	53.72	23.90	-27.30	-2.80	-29.65	-49.52
16.5-17.5	51.17	25.76	-27.60	-3.03	-30.59	-50.94
17.5-18.5	48.66	27.66	-27.90	-3.26	-31.49	-52.44
18.5-19.5	46.19	29.60	-28.20	-3.50	-32.34	-54.00
19.5-20.5	43.76	31.58	-28.50	-3.74	-33.14	-55.68
20.5-21.5	41.37	33.60	-28.80	-4.00	-33.89	-57.39
21.5-22.5	39.01	35.66	-29.10	-4.26	-34.59	-59.13
22.5-23.5	36.69	37.76	-29.40	-4.53	-35.24	-60.91
23.5-24.5	34.41	39.90	-29.70	-4.81	-35.84	-62.74
24.5-25.5	32.17	42.08	-30.00	-5.10	-36.39	-64.61
25.5-26.5	30.00	44.30	-30.30	-5.40	-36.89	-66.54

Table 14.7. Allocation of the total cost of retiring during 1970, \$10.42, to each vintage.

Year (a)	Retired (b)	CPI-U (c)	Ratio of CPI-U to 39.00 (d)	Adjusted retired (e)	Factor (f)	Allocated cost of retiring (g)
1962	14.00	65.7	1.68	18.53	.2996	3.12
1963	14.00	61.0	1.56	21.90	.3541	3.69
1964	4.00	57.1	1.46	5.88	.0917	.98
1965	7.00	54.2	1.39	9.69	.0000	.00
1966	4.00	49.4	1.27	8.87	.1434	1.49
1967	4.00	44.8	1.14	4.54	.0735	.77
1968	2.00	41.9	1.07	2.15	.0397	.46
1969	0.00	40.7	1.04	.00	.0000	.00
1970	42.00	39.0	1.00	61.84	.0000	10.42

NEWS RELEASE

BUREAU OF LABOR STATISTICS
U. S. D E P A R T M E N T O F L A B O R



Transmission of material in this release is embargoed until
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CONSUMER PRICE INDEX – DECEMBER 2017

The Consumer Price Index for All Urban Consumers (CPI-U) increased 0.1 percent in December on a seasonally adjusted basis, the U.S. Bureau of Labor Statistics reported today. Over the last 12 months, the all items index rose 2.1 percent before seasonal adjustment.

An increase of 0.4 percent in the shelter index accounted for almost 80 percent of the 1-month all items increase. The food index rose in December, with the indexes for food at home and food away from home both increasing. The energy index, which rose sharply in November, declined in December as the gasoline index decreased.

The index for all items less food and energy increased 0.3 percent in December, its largest increase since January 2017. Along with the shelter index, the indexes for medical care, used cars and trucks, new vehicles, and motor vehicle insurance were among those that increased in December. The indexes for apparel, airline fares, and tobacco all declined over the month.

The all items index rose 2.1 percent for the 12 months ending December, compared to 2.2 percent for the 12 months ending November. The index for all items less food and energy increased 1.8 percent over the last year; the 12-month change has now been either 1.7 or 1.8 percent for eight consecutive months. The food index rose 1.6 percent over the past year; the index for energy increased 6.9 percent, with all of its major component indexes rising during 2017.

Chart 1. One-month percent change in CPI for All Urban Consumers (CPI-U), seasonally adjusted, Dec. 2016 - Dec. 2017
Percent change

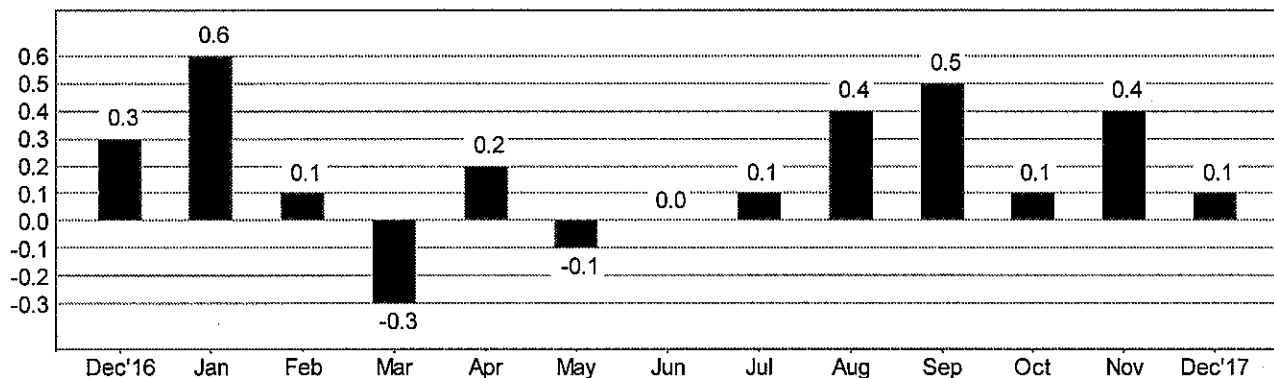


Chart 2. 12-month percent change in CPI for All Urban Consumers (CPI-U), not seasonally adjusted, Dec. 2016 - Dec. 2017

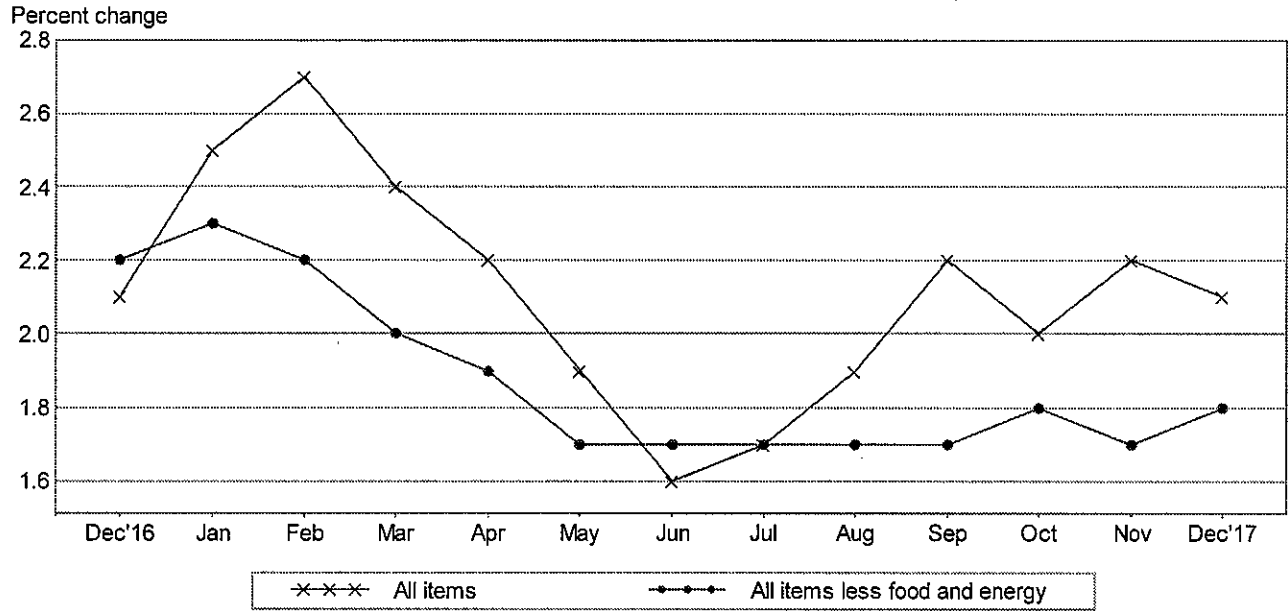


Table A. Percent changes in CPI for All Urban Consumers (CPI-U): U.S. city average

	Seasonally adjusted changes from preceding month							Un-adjusted 12-mos. ended Dec. 2017
	June 2017	July 2017	Aug. 2017	Sep. 2017	Oct. 2017	Nov. 2017	Dec. 2017	
All items0	.1	.4	.5	.1	.4	.1	2.1
Food0	.2	.1	.1	.0	.0	.2	1.6
Food at home	-.1	.2	-.2	.0	.0	-.1	.1	.9
Food away from home ¹0	.2	.3	.3	.1	.2	.2	2.5
Energy	-1.6	-1	2.8	6.1	-1.0	3.9	-1.2	6.9
Energy commodities	-2.7	.0	6.1	12.6	-2.3	7.1	-2.5	10.8
Gasoline (all types)	-2.8	.0	6.3	13.1	-2.4	7.3	-2.7	10.7
Fuel oil ¹	-3.7	-2.0	2.9	8.2	2.3	5.0	3.0	15.2
Energy services	-.5	-.2	-.1	-.2	.4	.6	.3	3.1
Electricity	-.6	.4	.0	.0	.5	.5	.1	2.6
Utility (piped) gas service	-.2	-2.3	-.5	-.8	.3	.6	1.2	4.7
All items less food and energy1	.1	.2	.1	.2	.1	.3	1.8
Commodities less food and energy commodities	-.1	-.1	-.1	-.2	.1	-.1	.2	-.7
New vehicles	-.3	-.5	.0	-.4	-.2	.3	.6	-.5
Used cars and trucks	-.7	-.5	-.2	-.2	.7	1.0	1.4	-1.0
Apparel	-.1	.3	.1	-.1	-.1	-1.3	-.5	-1.6
Medical care commodities7	1.0	-.1	-.8	.0	.6	1.0	2.3
Services less energy services2	.2	.4	.2	.3	.2	.3	2.6
Shelter2	.1	.5	.3	.3	.2	.4	3.2
Transportation services2	.2	.4	.3	.2	.1	.3	3.7
Medical care services3	.3	.2	.1	.3	-.1	.2	1.6

¹ Not seasonally adjusted.

Food

The food index increased 0.2 percent in December. The index for food at home rose 0.1 percent, largely due to a 0.9-percent increase in the index for meats, poultry, fish, and eggs, its largest increase since June 2015. The index for cereals and bakery products also rose in December, increasing 0.2 percent after a 0.2-percent decline in November.

The remaining major grocery store food group indexes declined in December. The index for dairy and related products fell 0.4 percent in December after rising in November. The index for fruits and vegetables declined 0.2 percent, and the indexes for nonalcoholic beverages and other food at home both fell 0.1 percent.

The index for food away from home rose 0.2 percent in December, the same increase as in November. Over the last 12 months, the food at home index rose 0.9 percent, and the index for food away from home increased 2.5 percent.

Energy

The energy index declined 1.2 percent in December following a 3.9-percent increase in November. The gasoline index fell 2.7 percent in December after rising 7.3 percent in November. (Before seasonal adjustment, gasoline prices decreased 3.3 percent in December.) The electricity index increased 0.1 percent in December. The index for natural gas increased 1.2 percent, its largest increase since May 2017.

All the major energy component indexes increased over the past 12 months. The gasoline index rose 10.7 percent, the electricity index advanced 2.6 percent, and the index for natural gas increased 4.7 percent.

All items less food and energy

The index for all items less food and energy increased 0.3 percent in December and rose 1.8 percent over the last 12 months. The shelter index rose 0.4 percent in December following a 0.2-percent increase in November. The rent index increased 0.4 percent over the month, and the index for owners' equivalent rent advanced 0.3 percent. The index for lodging away from home increased 0.8 percent after falling in November.

The medical care index increased 0.3 percent in December. The index for prescription drugs rose 1.0 percent in December after increasing 0.6 percent in November. The indexes for hospital services and physicians' services also increased, both rising 0.3 percent. The index for used cars and trucks also rose in December, increasing 1.4 percent. The new vehicles index rose 0.6 percent in December following a 0.3-percent increase in November; the index for motor vehicle insurance also increased 0.6 percent. The indexes for education, communication, and recreation all increased 0.1 percent in December.

In contrast, the apparel index fell 0.5 percent in December, its fourth consecutive decline. The tobacco index fell 0.6 percent in December after rising in each of the prior 3 months. The index for airline fares fell 0.5 percent after a 2.4-percent decrease the prior month. The indexes for household furnishings and operations and for personal care were both unchanged in December.

Not seasonally adjusted CPI measures

The Consumer Price Index for All Urban Consumers (CPI-U) increased 2.1 percent over the last 12 months to an index level of 246.524 (1982-84=100). For the month, the index declined 0.1 percent prior to seasonal adjustment.

The Consumer Price Index for Urban Wage Earners and Clerical Workers (CPI-W) increased 2.2 percent over the last 12 months to an index level of 240.526 (1982-84=100). For the month, the index declined 0.1 percent prior to seasonal adjustment.

The Chained Consumer Price Index for All Urban Consumers (C-CPI-U) increased 2.0 percent over the last 12 months. For the month, the index decreased 0.1 percent on a not seasonally adjusted basis. Please note that the indexes for the past 10 to 12 months are subject to revision.

Year in Review (December to December)

The all items CPI rose 2.1 percent in 2017, the same increase as in 2016, but larger than the 2014 and 2015 increases. It was also larger than the 1.6-percent average annual increase over the past 10 years.

The food index, which declined 0.2 percent in 2016, increased 1.6 percent in 2017. The index for food at home rose 0.9 percent in 2017 after falling in 2015 and 2016.

The six major grocery store food group indexes were mixed in 2017, with three increases, two declines, and one unchanged. The index for meats, poultry, fish, and eggs increased 2.8 percent after declining in 2015 and 2016. The beef index rose 3.5 percent in 2017, and the index for eggs increased 11.6 percent. The index for fruits and vegetables rose 1.5 percent in 2017 after falling 2.4 percent in 2016. The index for other food at home also increased in 2017, rising 0.5 percent.

The index for cereals and bakery products fell 0.6 percent in 2017, similar to its 0.7-percent decline the prior year. The index for dairy and related products fell 0.5 percent in 2017, its third consecutive yearly decrease. The index for nonalcoholic beverages was unchanged in 2017 after falling in 2016.

The index for food away from home rose 2.5 percent in 2017 after a 2.3-percent increase the prior year. Over the last 10 years, the food index rose at an annual rate of 2.0 percent. The food at home index rose at a 1.5-percent rate, and the index for food away from home increased at a 2.6-percent rate since December 2007.

The energy index rose 6.9 percent in 2017 after a 5.4-percent increase in 2016. The gasoline index increased 10.7 percent in 2017 following a 9.1-percent increase in 2016. The index for natural gas also increased for the second straight year, rising 4.7 percent in 2017 after increasing 7.8 percent in 2016. The electricity index increased 2.6 percent in 2017 after rising 0.7 percent in 2016. Despite the recent increases, the energy index declined at a 0.5-percent annual rate over the past 10 years.

The index for all items less food and energy rose 1.8 percent in 2017, a smaller increase than its 2.2-percent rise in 2016. The shelter index rose 3.2 percent in 2017 following a 3.6-percent increase in 2016. The rent index rose 3.7 percent in 2017, while the index for owners' equivalent rent increased 3.2 percent.

The medical care index increased 1.8 percent in 2017, a substantial deceleration from its 4.1-percent increase in 2016. The index for prescription drugs rose 2.8 percent in 2017. The index for hospital services rose 5.1 percent, while the physicians' services index declined 1.8 percent.

The index for motor vehicle insurance rose 7.9 percent in 2017 following a 7.0-percent increase in 2016. The index for new vehicles fell 0.5 percent in 2017 after rising modestly in previous years; the index for used cars and trucks declined 1.0 percent after a 3.5-percent decline the prior year.

The education index increased 2.0 percent in 2017, the smallest annual increase in the history of the index, which dates to 1993. The index for communication declined 4.9 percent in 2017, its eighth consecutive yearly decline. The recreation index rose 1.5 percent, and the index for personal care increased 0.9 percent. The index for tobacco increased 6.5 percent, and the alcoholic beverages index rose 1.4 percent.

The index for airline fares decreased 4.0 percent in 2017, its fifth consecutive yearly decline. The apparel index fell 1.6 percent, its fourth straight annual decrease. The index for household furnishings and operations also continued to fall, declining 0.8 percent in 2017 after falling 1.1 percent the prior year.

The Consumer Price Index for January 2018 is scheduled to be released on Wednesday, February 14, 2018, at 8:30 a.m. (EST).

Consumer Price Index Geographic Revision for 2018

In January 2018, BLS will introduce a new geographic area sample for the Consumer Price Index (CPI). The 2018 revision utilizes the 2010 Decennial Census and incorporates an updated area sample design, changes the frequency of publication for several local area indexes, and establishes some new local area and aggregate indexes. The first indexes using the new structure will be published in February 2018. Additional information on the geographic revision is available at: www.bls.gov/cpi/georevision2018.htm.

Technical Note

Brief Explanation of the CPI

The Consumer Price Index (CPI) measures the change in prices paid by consumers for goods and services. The CPI reflects spending patterns for each of two population groups: all urban consumers and urban wage earners and clerical workers. The all urban consumer group represents about 89 percent of the total U.S. population. It is based on the expenditures of almost all residents of urban or metropolitan areas, including professionals, the self-employed, the poor, the unemployed, and retired people, as well as urban wage earners and clerical workers. Not included in the CPI are the spending patterns of people living in rural nonmetropolitan areas, farming families, people in the Armed Forces, and those in institutions, such as prisons and mental hospitals. Consumer inflation for all urban consumers is measured by two indexes, namely, the Consumer Price Index for All Urban Consumers (CPI-U) and the Chained Consumer Price Index for All Urban Consumers (C-CPI-U).

The Consumer Price Index for Urban Wage Earners and Clerical Workers (CPI-W) is based on the expenditures of households included in the CPI-U definition that meet two requirements: more than one-half of the household's income must come from clerical or wage occupations, and at least one of the household's earners must have been employed for at least 37 weeks during the previous 12 months. The CPI-W population represents about 28 percent of the total U.S. population and is a subset of the CPI-U population.

The CPIs are based on prices of food, clothing, shelter, fuels, transportation, doctors' and dentists' services, drugs, and other goods and services that people buy for day-to-day living. Prices are collected each month in 87 urban areas across the country from about 6,000 housing units and approximately 24,000 retail establishments (department stores, supermarkets, hospitals, filling stations, and other types of stores and service establishments). All taxes directly associated with the purchase and use of items are included in the index. Prices of fuels and a few other items are obtained every month in all 87 locations. Prices of most other commodities and services are collected every month in the three largest geographic areas and every other month in other areas. Prices of most goods and services are obtained by personal visits or telephone calls by the Bureau's trained representatives.

In calculating the index, price changes for the various items in each location are aggregated using weights, which represent their importance in the spending of the appropriate population group. Local data are then combined to obtain a U.S. city average. For the CPI-U and CPI-W, separate indexes are also published by size of city, by region of the country, for cross-classifications of regions and population-size classes, and for 27 selected local areas. Area indexes do not measure differences in the level of prices among cities; they only measure the average change in prices for each area since the base period. For the C-CPI-U, data are issued only at the national level. The CPI-U and CPI-W are considered final when released, but the C-CPI-U is issued in preliminary form and subject to three subsequent quarterly revisions.

The index measures price change from a designed reference date. For most of the CPI-U and the CPI-W, the reference base is 1982-84 equals 100. The reference base for the C-CPI-U is December 1999 equals 100. An increase of 7 percent from the reference base, for example, is shown as 107.000. Alternatively, that relationship can also be expressed as the price of a base period market basket of goods and services rising from \$100 to \$107.

Sampling Error in the CPI

The CPI is a statistical estimate that is subject to sampling error because it is based upon a sample of retail prices and not the complete universe of all prices. BLS calculates and publishes estimates of the 1-month, 2-month, 6-month, and 12-month percent change standard errors annually for the CPI-U. These standard error estimates can be used to construct confidence intervals for hypothesis testing. For example, the estimated standard error of the 1-month percent change is 0.03 percent for the U.S. all items CPI. This means that if we repeatedly sample from the universe of all retail prices using the same methodology, and estimate a percentage change for each sample, then 95 percent of these estimates will be within 0.06 percent of the 1-month percentage change based on all retail prices. For example, for a 1-month change of 0.2 percent in the all items CPI-U, we are 95 percent confident that the actual percent change based on all retail prices would fall between 0.14 and 0.26 percent. For the latest data, including information on how to use the estimates of standard error, see <https://www.bls.gov/cpi/tables/variance-estimates/2016.pdf>.

Calculating Index Changes

Movements of the indexes from 1 month to another are usually expressed as percent changes rather than changes in index points, because index point changes are affected by the level of the index in relation to its base period, while percent changes are not. The following table shows an example of using index values to calculate percent changes:

	Item A	Item B	Item C
Year I	112.500	225.000	110.000
Year II	121.500	243.000	128.000
Change in index points	9.000	18.000	18.000
Percent change	$9.0/112.500 \times 100 = 8.0$	$18.0/225.000 \times 100 = 8.0$	$18.0/110.000 \times 100 = 16.4$

Use of Seasonally Adjusted and Unadjusted Data

The Consumer Price Index (CPI) produces both unadjusted and seasonally adjusted data. Seasonally adjusted data are computed using seasonal factors derived by the X-13ARIMA-SEATS seasonal adjustment method. These factors are updated each February, and the new factors are used to revise the previous 5 years of seasonally adjusted data. For more information on data revision scheduling, please see the Fact Sheet on Seasonal Adjustment at <https://www.bls.gov/cpi/seasonal-adjustment/questions-and-answers.htm> and the Timeline of Seasonal Adjustment Methodological Changes at <https://www.bls.gov/cpi/seasonal-adjustment/timeline-seasonal-adjustment-methodology-changes.htm>.

For analyzing short-term price trends in the economy, seasonally adjusted changes are usually preferred since they eliminate the effect of changes that normally occur at the same time and in about the same magnitude every year—such as price movements resulting from weather events, production cycles, model changeovers, holidays, and sales. This allows data users to focus on changes that are not typical for the time of year. The unadjusted data are of primary interest to consumers concerned about the prices they actually pay. Unadjusted data are also used extensively for escalation purposes. Many collective bargaining contract agreements and pension plans, for example, tie compensation changes to the Consumer Price Index before adjustment for seasonal variation. BLS advises against the use of seasonally adjusted data in escalation agreements because seasonally adjusted series are revised annually.

Intervention Analysis

The Bureau of Labor Statistics uses intervention analysis seasonal adjustment for some CPI series. Sometimes extreme values or sharp movements can distort the underlying seasonal pattern of price change. Intervention analysis seasonal adjustment is a process by which the distortions caused by such unusual events are estimated and removed from the data prior to calculation of seasonal factors. The resulting seasonal factors, which more accurately represent the seasonal pattern, are then applied to the unadjusted data.

For example, this procedure was used for the motor fuel series to offset the effects of the 2009 return to normal pricing after the worldwide economic downturn in 2008. Retaining this outlier data during seasonal factor calculation would distort the computation of the seasonal portion of the time series data for motor fuel, so it was estimated and removed from the data prior to seasonal adjustment. Following that, seasonal factors were calculated based on this "prior adjusted" data. These seasonal factors represent a clearer picture of the seasonal pattern in the data. The last step is for motor fuel seasonal factors to be applied to the unadjusted data.

For the seasonal factors introduced in January 2017, BLS adjusted 40 series using intervention analysis seasonal adjustment, including selected food and beverage items, motor fuels, and natural gas.

Revision of Seasonally Adjusted Indexes

Seasonally adjusted data, including the U.S. city average all items index levels, are subject to revision for up to 5 years after their original release. Every year, economists in the CPI calculate new seasonal factors for seasonally adjusted series and apply them to the last 5 years of data. Seasonally adjusted indexes beyond the last 5 years of data are considered to be final and not subject to revision. In January 2017, revised seasonal factors and seasonally adjusted indexes for 2012 to 2016 were calculated and published. For series which are directly adjusted using the Census X-13ARIMA-SEATS seasonal adjustment software, the seasonal factors for 2016 will be applied to data for 2017 to produce the seasonally adjusted 2017 indexes. Series which are indirectly seasonally adjusted by summing seasonally adjusted component series have seasonal factors which are derived and are therefore not available in advance.

Determining Seasonal Status

Each year the seasonal status of every series is reevaluated based upon certain statistical criteria. Using these criteria, BLS economists determine whether a series should change its status from "not seasonally adjusted" to "seasonally adjusted", or vice versa. If any of the 81 components of the U.S. city average all items index change their seasonal adjustment status from seasonally adjusted to not seasonally adjusted, not seasonally adjusted data will be used in the aggregation of the dependent series for the last 5 years, but the seasonally adjusted indexes before that period will not be changed. Twenty-seven of the 81 components of the U.S. city average all items index are not seasonally adjusted for 2017.

Contact Information

For additional information about the CPI visit www.bls.gov/cpi or contact the CPI Information and Analysis Section at 202-691-7000 or cpi_info@bls.gov.

For additional information on seasonal adjustment in the CPI visit <https://www.bls.gov/cpi/seasonal-adjustment/home.htm> or contact the CPI seasonal adjustment section at 202-691-6968 or cpiseas@bls.gov.

Information from this release will be made available to sensory impaired individuals upon request.
Voice phone: 202-691-5200; Federal Relay Service: 1-800-877-8339.

Table 24. Historical Consumer Price Index for All Urban Consumers (CPI-U): U. S. city average, all items

(1982-84=100, unless otherwise noted)

Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
1913	9.8	9.8	9.8	9.8	9.7	9.8	9.9	9.9	10.0	10.0	10.1	10.0
1914	10.0	9.9	9.9	9.8	9.9	9.9	10.0	10.2	10.2	10.1	10.2	10.1
1915	10.1	10.0	9.9	10.0	10.1	10.1	10.1	10.1	10.1	10.2	10.3	10.3
1916	10.4	10.4	10.5	10.6	10.7	10.8	10.8	10.9	11.1	11.3	11.5	11.6
1917	11.7	12.0	12.0	12.6	12.8	13.0	12.8	13.0	13.3	13.5	13.5	13.7
1918	14.0	14.1	14.0	14.2	14.5	14.7	15.1	15.4	15.7	16.0	16.3	16.7
1919	16.5	16.2	16.4	16.7	16.9	16.9	17.4	17.7	17.8	18.1	18.5	18.9
1920	19.3	19.5	19.7	20.3	20.6	20.9	20.8	20.3	20.0	19.9	19.8	19.4
1921	19.0	18.4	18.3	18.1	17.7	17.6	17.7	17.7	17.5	17.5	17.4	17.3
1922	16.9	16.9	16.7	16.7	16.7	16.7	16.8	16.6	16.6	16.7	16.8	16.9
1923	16.8	16.8	16.8	16.9	16.9	17.0	17.2	17.1	17.2	17.3	17.3	17.3
1924	17.3	17.2	17.1	17.0	17.0	17.0	17.1	17.0	17.1	17.2	17.2	17.3
1925	17.3	17.2	17.3	17.2	17.3	17.5	17.7	17.7	17.7	17.7	18.0	17.9
1926	17.9	17.9	17.8	17.9	17.8	17.7	17.5	17.4	17.5	17.6	17.7	17.7
1927	17.5	17.4	17.3	17.3	17.4	17.6	17.3	17.2	17.3	17.4	17.3	17.3
1928	17.3	17.1	17.1	17.1	17.2	17.1	17.1	17.1	17.3	17.2	17.2	17.1
1929	17.1	17.1	17.0	16.9	17.0	17.1	17.3	17.3	17.3	17.3	17.3	17.2
1930	17.1	17.0	16.9	17.0	16.9	16.8	16.6	16.5	16.6	16.5	16.4	16.1
1931	15.9	15.7	15.6	15.5	15.3	15.1	15.1	15.1	15.0	14.9	14.7	14.6
1932	14.3	14.1	14.0	13.9	13.7	13.6	13.6	13.5	13.4	13.3	13.2	13.1
1933	12.9	12.7	12.6	12.6	12.6	12.7	13.1	13.2	13.2	13.2	13.2	13.2
1934	13.2	13.3	13.3	13.3	13.3	13.4	13.4	13.4	13.6	13.5	13.5	13.4
1935	13.6	13.7	13.7	13.8	13.8	13.7	13.7	13.7	13.7	13.7	13.8	13.8
1936	13.8	13.8	13.7	13.7	13.7	13.8	13.9	14.0	14.0	14.0	14.0	14.0
1937	14.1	14.1	14.2	14.3	14.4	14.4	14.5	14.5	14.6	14.6	14.5	14.4
1938	14.2	14.1	14.1	14.2	14.1	14.1	14.1	14.1	14.1	14.0	14.0	14.0
1939	14.0	13.9	13.9	13.8	13.8	13.8	13.8	13.8	14.1	14.0	14.0	14.0
1940	13.9	14.0	14.0	14.0	14.0	14.1	14.0	14.0	14.0	14.0	14.0	14.1
1941	14.1	14.1	14.2	14.3	14.4	14.7	14.7	14.9	15.1	15.3	15.4	15.5
1942	15.7	15.8	16.0	16.1	16.3	16.3	16.4	16.5	16.5	16.7	16.8	16.9
1943	16.9	16.9	17.2	17.4	17.5	17.5	17.4	17.3	17.4	17.4	17.4	17.4
1944	17.4	17.4	17.4	17.5	17.5	17.6	17.7	17.7	17.7	17.7	17.7	17.8
1945	17.8	17.8	17.8	17.8	17.9	18.1	18.1	18.1	18.1	18.1	18.1	18.2
1946	18.2	18.1	18.3	18.4	18.5	18.7	19.8	20.2	20.4	20.8	21.3	21.5
1947	21.5	21.5	21.9	21.9	21.9	22.0	22.2	22.5	23.0	23.0	23.1	23.4
1948	23.7	23.5	23.4	23.8	23.9	24.1	24.4	24.5	24.5	24.4	24.2	24.1
1949	24.0	23.8	23.8	23.9	23.8	23.9	23.7	23.8	23.9	23.7	23.8	23.6
1950	23.5	23.5	23.6	23.6	23.7	23.8	24.1	24.3	24.4	24.6	24.7	25.0
1951	25.4	25.7	25.8	25.8	25.9	25.9	25.9	25.9	26.1	26.2	26.4	26.5
1952	26.5	26.3	26.3	26.4	26.4	26.5	26.7	26.7	26.7	26.7	26.7	26.7
1953	26.6	26.5	26.6	26.6	26.7	26.8	26.8	26.9	26.9	27.0	26.9	26.9
1954	26.9	26.9	26.9	26.8	26.9	26.9	26.9	26.9	26.8	26.8	26.8	26.7
1955	26.7	26.7	26.7	26.7	26.7	26.7	26.8	26.8	26.9	26.9	26.9	26.8
1956	26.8	26.8	26.8	26.9	27.0	27.2	27.4	27.3	27.4	27.5	27.5	27.6
1957	27.6	27.7	27.8	27.9	28.0	28.1	28.3	28.3	28.3	28.3	28.4	28.4
1958	28.6	28.6	28.8	28.9	28.9	28.9	29.0	28.9	28.9	28.9	29.0	28.9
1959	29.0	28.9	28.9	29.0	29.0	29.1	29.2	29.2	29.3	29.4	29.4	29.4
1960	29.3	29.4	29.4	29.5	29.5	29.6	29.6	29.6	29.6	29.8	29.8	29.8
1961	29.8	29.8	29.8	29.8	29.8	29.8	30.0	29.9	30.0	30.0	30.0	30.0
1962	30.0	30.1	30.1	30.2	30.2	30.2	30.3	30.3	30.4	30.4	30.4	30.4
1963	30.4	30.4	30.5	30.5	30.5	30.6	30.7	30.7	30.7	30.8	30.8	30.9
1964	30.9	30.9	30.9	30.9	30.9	31.0	31.1	31.0	31.1	31.1	31.2	31.2
1965	31.2	31.2	31.3	31.4	31.4	31.6	31.6	31.6	31.6	31.7	31.7	31.8
1966	31.8	32.0	32.1	32.3	32.3	32.4	32.5	32.7	32.7	32.9	32.9	32.9
1967	32.9	32.9	33.0	33.1	33.2	33.3	33.4	33.5	33.6	33.7	33.8	33.9
1968	34.1	34.2	34.3	34.4	34.5	34.7	34.9	35.0	35.1	35.3	35.4	35.5
1969	35.6	35.8	36.1	36.3	36.4	36.6	36.8	37.0	37.1	37.3	37.5	37.7

See footnotes at end of table.

Table 24. Historical Consumer Price Index for All Urban Consumers (CPI-U): U. S. city average, all items-Continued

(1982-84=100, unless otherwise noted)

Year	Semiannual averages		Annual avg.	Percent change from previous	
	1st half	2nd half		Dec.	Annual avg.
1913	-	-	9.9	-	-
1914	-	-	10.0	1.0	1.0
1915	-	-	10.1	2.0	1.0
1916	-	-	10.9	12.6	7.9
1917	-	-	12.8	18.1	17.4
1918	-	-	15.1	20.4	18.0
1919	-	-	17.3	14.5	14.6
1920	-	-	20.0	2.6	15.6
1921	-	-	17.9	-10.8	-10.5
1922	-	-	16.8	-2.3	-6.1
1923	-	-	17.1	2.4	1.8
1924	-	-	17.1	.0	.0
1925	-	-	17.5	3.5	2.3
1926	-	-	17.7	-1.1	1.1
1927	-	-	17.4	-2.3	-1.7
1928	-	-	17.1	-1.2	-1.7
1929	-	-	17.1	.6	.0
1930	-	-	16.7	-6.4	-2.3
1931	-	-	15.2	-9.3	-9.0
1932	-	-	13.7	-10.3	-9.9
1933	-	-	13.0	.8	-5.1
1934	-	-	13.4	1.5	3.1
1935	-	-	13.7	3.0	2.2
1936	-	-	13.9	1.4	1.5
1937	-	-	14.4	2.9	3.6
1938	-	-	14.1	-2.8	-2.1
1939	-	-	13.9	.0	-1.4
1940	-	-	14.0	.7	.7
1941	-	-	14.7	9.9	5.0
1942	-	-	16.3	9.0	10.9
1943	-	-	17.3	3.0	6.1
1944	-	-	17.6	2.3	1.7
1945	-	-	18.0	2.2	2.3
1946	-	-	19.5	18.1	8.3
1947	-	-	22.3	8.8	14.4
1948	-	-	24.1	3.0	8.1
1949	-	-	23.8	-2.1	-1.2
1950	-	-	24.1	5.9	1.3
1951	-	-	26.0	6.0	7.9
1952	-	-	26.5	.8	1.9
1953	-	-	26.7	.7	.8
1954	-	-	26.9	-.7	.7
1955	-	-	26.8	.4	-.4
1956	-	-	27.2	3.0	1.5
1957	-	-	28.1	2.9	3.3
1958	-	-	28.9	1.8	2.8
1959	-	-	29.1	1.7	.7
1960	-	-	29.6	1.4	1.7
1961	-	-	29.9	.7	1.0
1962	-	-	30.2	1.3	1.0
1963	-	-	30.6	1.6	1.3
1964	-	-	31.0	1.0	1.3
1965	-	-	31.5	1.9	1.6
1966	-	-	32.4	3.5	2.9
1967	-	-	33.4	3.0	3.1
1968	-	-	34.8	4.7	4.2
1969	-	-	36.7	6.2	5.5

See footnotes at end of table.

Table 24. Historical Consumer Price Index for All Urban Consumers (CPI-U): U. S. city average, all items-Continued

(1982-84=100, unless otherwise noted)

Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
1970	37.8	38.0	38.2	38.5	38.6	38.8	39.0	39.0	39.2	39.4	39.6	39.8
1971	39.8	39.9	40.0	40.1	40.3	40.6	40.7	40.8	40.8	40.9	40.9	41.1
1972	41.1	41.3	41.4	41.5	41.6	41.7	41.9	42.0	42.1	42.3	42.4	42.5
1973	42.6	42.9	43.3	43.6	43.9	44.2	44.3	45.1	45.2	45.6	45.9	46.2
1974	46.6	47.2	47.8	48.0	48.6	49.0	49.4	50.0	50.6	51.1	51.5	51.9
1975	52.1	52.5	52.7	52.9	53.2	53.6	54.2	54.3	54.6	54.9	55.3	55.5
1976	55.6	55.8	55.9	56.1	56.5	56.8	57.1	57.4	57.6	57.9	58.0	58.2
1977	58.5	59.1	59.5	60.0	60.3	60.7	61.0	61.2	61.4	61.6	61.9	62.1
1978	62.5	62.9	63.4	63.9	64.5	65.2	65.7	66.0	66.5	67.1	67.4	67.7
1979	68.3	69.1	69.8	70.6	71.5	72.3	73.1	73.8	74.6	75.2	75.9	76.7
1980	77.8	78.9	80.1	81.0	81.8	82.7	82.7	83.3	84.0	84.8	85.5	86.3
1981	87.0	87.9	88.5	89.1	89.8	90.6	91.6	92.3	93.2	93.4	93.7	94.0
1982	94.3	94.6	94.5	94.9	95.8	97.0	97.5	97.7	97.9	98.2	98.0	97.6
1983	97.8	97.9	97.9	98.6	99.2	99.5	99.9	100.2	100.7	101.0	101.2	101.3
1984	101.9	102.4	102.6	103.1	103.4	103.7	104.1	104.5	105.0	105.3	105.3	105.3
1985	105.5	106.0	106.4	106.9	107.3	107.6	107.8	108.0	108.3	108.7	109.0	109.3
1986	109.6	109.3	108.8	108.6	108.9	109.5	109.5	109.7	110.2	110.3	110.4	110.5
1987	111.2	111.6	112.1	112.7	113.1	113.5	113.8	114.4	115.0	115.3	115.4	115.4
1988	115.7	116.0	116.5	117.1	117.5	118.0	118.5	119.0	119.8	120.2	120.3	120.5
1989	121.1	121.6	122.3	123.1	123.8	124.1	124.4	124.6	125.0	125.6	125.9	126.1
1990	127.4	128.0	128.7	128.9	129.2	129.9	130.4	131.6	132.7	133.5	133.8	133.8
1991	134.6	134.8	135.0	135.2	135.6	136.0	136.2	136.6	137.2	137.4	137.8	137.9
1992	138.1	138.6	139.3	139.5	139.7	140.2	140.5	140.9	141.3	141.8	142.0	141.9
1993	142.6	143.1	143.6	144.0	144.2	144.4	144.4	144.8	145.1	145.7	145.8	145.8
1994	146.2	146.7	147.2	147.4	147.5	148.0	148.4	149.0	149.4	149.5	149.7	149.7
1995	150.3	150.9	151.4	151.9	152.2	152.5	152.5	152.9	153.2	153.7	153.6	153.5
1996	154.4	154.9	155.7	156.3	156.6	156.7	157.0	157.3	157.8	158.3	158.6	158.6
1997	159.1	159.6	160.0	160.2	160.1	160.3	160.5	160.8	161.2	161.6	161.5	161.3
1998	161.6	161.9	162.2	162.5	162.8	163.0	163.2	163.4	163.6	164.0	164.0	163.9
1999	164.3	164.5	165.0	166.2	166.2	166.2	166.7	167.1	167.9	168.2	168.3	168.3
2000	168.8	169.8	171.2	171.3	171.5	172.4	172.8	172.8	173.7	174.0	174.1	174.0
2001	175.1	175.8	176.2	176.9	177.7	178.0	177.5	177.5	178.3	177.7	177.4	176.7
2002	177.1	177.8	178.8	179.8	179.8	179.9	180.1	180.7	181.0	181.3	181.3	180.9
2003	181.7	183.1	184.2	183.8	183.5	183.7	183.9	184.6	185.2	185.0	184.5	184.3
2004	185.2	186.2	187.4	188.0	189.1	189.7	189.4	189.5	189.9	190.9	191.0	190.3
2005	190.7	191.8	193.3	194.6	194.4	194.5	195.4	196.4	198.8	199.2	197.6	196.8
2006	198.3	198.7	199.8	201.5	202.5	202.9	203.5	203.9	202.9	201.8	201.5	201.8
2007	202.416	203.499	205.352	206.686	207.949	208.352	208.299	207.917	208.490	208.936	210.177	210.036
2008	211.080	211.693	213.528	214.823	216.632	218.815	219.964	219.086	218.783	216.573	212.425	210.228
2009	211.143	212.193	212.709	213.240	213.856	215.693	215.351	215.834	215.969	216.177	216.330	215.949
2010	216.687	216.741	217.631	218.009	218.178	217.965	218.011	218.312	218.439	218.711	218.803	219.179
2011	220.223	221.309	223.467	224.906	225.964	225.722	225.922	226.545	226.889	226.421	226.230	225.672
2012	226.665	227.663	229.392	230.085	229.815	229.478	229.104	230.379	231.407	231.317	230.221	229.601
2013	230.280	232.166	232.773	232.531	232.945	233.504	233.596	233.877	234.149	233.546	233.069	233.049
2014	233.916	234.781	236.293	237.072	237.900	238.343	238.250	237.852	238.031	237.433	236.151	234.812
2015	233.707	234.722	236.119	236.599	237.805	238.638	238.654	238.316	237.945	237.838	237.336	236.525
2016	236.916	237.111	238.132	239.261	240.229	241.018	240.628	240.849	241.428	241.729	241.353	241.432
2017	242.839	243.603	243.801	244.524	244.733	244.955	244.786	245.519	246.819	246.663	246.669	246.524

See footnotes at end of table.

Table 24. Historical Consumer Price Index for All Urban Consumers (CPI-U): U. S. city average, all items-Continued

(1982-84=100, unless otherwise noted)

Year	Semiannual averages		Annual avg.	Percent change from previous	
	1st half	2nd half		Dec.	Annual avg.
1970	-	-	38.8	5.6	5.7
1971	-	-	40.5	3.3	4.4
1972	-	-	41.8	3.4	3.2
1973	-	-	44.4	8.7	6.2
1974	-	-	49.3	12.3	11.0
1975	-	-	53.8	6.9	9.1
1976	-	-	56.9	4.9	5.8
1977	-	-	60.6	6.7	6.5
1978	-	-	65.2	9.0	7.6
1979	-	-	72.6	13.3	11.3
1980	-	-	82.4	12.5	13.5
1981	-	-	90.9	8.9	10.3
1982	-	-	96.5	3.8	6.2
1983	-	-	99.6	3.8	3.2
1984	102.9	104.9	103.9	3.9	4.3
1985	106.6	108.5	107.6	3.8	3.6
1986	109.1	110.1	109.6	1.1	1.9
1987	112.4	114.9	113.6	4.4	3.6
1988	116.8	119.7	118.3	4.4	4.1
1989	122.7	125.3	124.0	4.6	4.8
1990	128.7	132.6	130.7	6.1	5.4
1991	135.2	137.2	136.2	3.1	4.2
1992	139.2	141.4	140.3	2.9	3.0
1993	143.7	145.3	144.5	2.7	3.0
1994	147.2	149.3	148.2	2.7	2.6
1995	151.5	153.2	152.4	2.5	2.8
1996	155.8	157.9	156.9	3.3	3.0
1997	159.9	161.2	160.5	1.7	2.3
1998	162.3	163.7	163.0	1.6	1.6
1999	165.4	167.8	166.6	2.7	2.2
2000	170.8	173.6	172.2	3.4	3.4
2001	176.6	177.5	177.1	1.6	2.8
2002	178.9	180.9	179.9	2.4	1.6
2003	183.3	184.6	184.0	1.9	2.3
2004	187.6	190.2	188.9	3.3	2.7
2005	193.2	197.4	195.3	3.4	3.4
2006	200.6	202.6	201.6	2.5	3.2
2007	205.709	208.976	207.342	4.1	2.8
2008	214.429	216.177	215.303	.1	3.8
2009	213.139	215.935	214.537	2.7	-.4
2010	217.535	218.576	218.056	1.5	1.6
2011	223.598	226.280	224.939	3.0	3.2
2012	228.850	230.338	229.594	1.7	2.1
2013	232.366	233.548	232.957	1.5	1.5
2014	236.384	237.088	236.736	.8	1.6
2015	236.265	237.769	237.017	.7	.1
2016	238.778	241.237	240.007	2.1	1.3
2017	244.076	246.163	245.120	2.1	2.1

* Data not available.

NOTE: Index applies to a month as a whole, not to any specific date.

Attorney General of Oklahoma
Data Request AG-9
Cause No. PUD 201700496

9-6 Please refer to Attachment B, which includes pages from the Consumer Price Index (CPI) (U. S. Department of Labor, Bureau of Labor Statistics, December 2017). For example, it shows that in 1979, the Annual Average inflation rate was 11.3%; in 1980, it was 13.5%; and in 1981, it was 10.3%. In preparing the past net salvage data that is shown on page VIII-41 through page VIII-60 of Direct Exhibit JJS-2, or in preparing Mr. Spanos's Future Net Salvage factor recommendations for Distribution and Transmission accounts, did Mr. Spanos adjust for the possibility that annual inflation in the future might be less than annual inflation had been in the past? If "yes," please explain how this adjustment was performed and cite to the pages in Direct Exhibit JJS-2, or in any workpapers, showing the adjustment for this factor.

Response*: The net salvage tables shown in part VIII of the Depreciation Study were prepared consistently for all accounts. Mr. Spanos did not adjust for the possibility that annual inflation may be different in the future from the past. The level of inflation is a function of the period of time as well as the inflation rate. Any adjustment for inflation would need to account for the fact that the historical period of time (i.e. the average age of retirements) is shorter than the average service life and probable life. Any attempt to adjust for historical inflation rates without properly considering the time period would be incorrect. Given the historical data, it is known that most of the retirements were for vintages subsequent to the 1970s/early 1980s which does not include the high inflation years stated in the question.

Response provided by:	<u>John Spanos</u>
Response provided on:	<u>March 19, 2018</u>
Contact & Phone No:	<u>Jason Bailey 405-559-3406</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Statement on Longer-Run Goals and Monetary Policy Strategy

Adopted effective January 24, 2012; as amended effective January 30, 2018

The Federal Open Market Committee (FOMC) is firmly committed to fulfilling its statutory mandate from the Congress of promoting maximum employment, stable prices, and moderate long-term interest rates. The Committee seeks to explain its monetary policy decisions to the public as clearly as possible. Such clarity facilitates well-informed decisionmaking by households and businesses, reduces economic and financial uncertainty, increases the effectiveness of monetary policy, and enhances transparency and accountability, which are essential in a democratic society.

Inflation, employment, and long-term interest rates fluctuate over time in response to economic and financial disturbances. Moreover, monetary policy actions tend to influence economic activity and prices with a lag. Therefore, the Committee's policy decisions reflect its longer-run goals, its medium-term outlook, and its assessments of the balance of risks, including risks to the financial system that could impede the attainment of the Committee's goals.

The inflation rate over the longer run is primarily determined by monetary policy, and hence the Committee has the ability to specify a longer-run goal for inflation. The Committee reaffirms its judgment that inflation at the rate of 2 percent, as measured by the annual change in the price index for personal consumption expenditures, is most consistent over the longer run with the Federal Reserve's statutory mandate. The Committee would be concerned if inflation were running persistently above or below this objective. Communicating this symmetric inflation goal clearly to the public helps keep longer-term inflation expectations firmly anchored, thereby fostering price stability and moderate long-term interest rates and enhancing the Committee's ability to promote maximum employment in the face of significant

economic disturbances. The maximum level of employment is largely determined by nonmonetary factors that affect the structure and dynamics of the labor market. These factors may change over time and may not be directly measurable. Consequently, it would not be appropriate to specify a fixed goal for employment; rather, the Committee's policy decisions must be informed by assessments of the maximum level of employment, recognizing that such assessments are necessarily uncertain and subject to revision. The Committee considers a wide range of indicators in making these assessments. Information about Committee participants' estimates of the longer-run normal rates of output growth and unemployment is published four times per year in the FOMC's Summary of Economic Projections. For example, in the most recent projections, the median of FOMC participants' estimates of the longer-run normal rate of unemployment was 4.6 percent.

In setting monetary policy, the Committee seeks to mitigate deviations of inflation from its longer-run goal and deviations of employment from the Committee's assessments of its maximum level. These objectives are generally complementary. However, under circumstances in which the Committee judges that the objectives are not complementary, it follows a balanced approach in promoting them, taking into account the magnitude of the deviations and the potentially different time horizons over which employment and inflation are projected to return to levels judged consistent with its mandate.

The Committee intends to reaffirm these principles and to make adjustments as appropriate at its annual organizational meeting each January.

**Oklahoma Gas and Electric Company
 Account 364 Poles, Towers, and Fixtures
 Net Salvage Using Annual Inflation Rate of 2%**

Year	Regular	Cost of Removal		Gross Salvage		Net Salvage	
	Retirements	Amount	Percent	Amount	Percent	Amount	Percent
A	B	C	D=C/B	E	F=E/B	G=E-C	H=G/B
1997	1,075,671	325,165	30%	437,445	41%	112,281	10%
1998	806,164	190,166	24%	612,238	76%	422,072	52%
1999	1,152,200	346,054	30%	291,066	25%	(54,988)	-5%
2000	1,847,854	267,058	14%	226,441	12%	(40,617)	-2%
2001	1,317,967	825,349	63%	319,351	24%	(505,998)	-38%
2002	3,839,897	1,768,646	46%	658,388	17%	(1,110,258)	-29%
2003	2,231,433	1,080,690	48%	462,233	21%	(618,457)	-28%
2004	2,604,783	1,446,146	56%	587,428	23%	(858,718)	-33%
2005	3,184,082	1,332,754	42%	288,172	9%	(1,044,582)	-33%
2006	3,716,298	2,291,108	62%	614,960	17%	(1,676,149)	-45%
2007	2,497,297	2,386,799	96%	3,006,625	120%	619,826	25%
2008	3,403,343	2,967,024	87%	813,097	24%	(2,153,926)	-63%
2009	2,985,131	2,758,627	92%	1,155,821	39%	(1,602,806)	-54%
2010	3,393,766	2,775,821	82%	1,150,395	34%	(1,625,426)	-48%
2011	3,908,694	2,765,566	71%	1,057,947	27%	(1,707,619)	-44%
2012	3,229,999	2,921,596	90%	933,367	29%	(1,988,229)	-62%
2013	3,686,199	3,164,593	86%	980,064	27%	(2,184,529)	-59%
2014	4,926,088	2,253,505	46%	1,103,198	22%	(1,150,307)	-23%
2015	3,333,448	3,767,547	113%	1,569,750	47%	(2,197,797)	-66%
2016	3,508,903	2,867,729	82%	1,160,826	33%	(1,706,902)	-49%
Total	56,649,216	38,501,944	68%	17,428,814	31%	(21,073,130)	-37%

Three-Year Moving Averages

1997-1999	1,011,345	287,129	28%	446,917	44%	159,788	16%
1998-2000	1,268,739	267,760	21%	376,582	30%	108,822	9%
1999-2001	1,439,340	479,487	33%	278,953	19%	(200,535)	-14%
2000-2002	2,335,239	953,684	41%	401,393	17%	(552,291)	-24%
2001-2003	2,463,099	1,224,895	50%	479,991	19%	(744,904)	-30%
2002-2004	2,892,037	1,431,827	50%	569,350	20%	(862,477)	-30%
2003-2005	2,673,432	1,286,530	48%	445,945	17%	(840,586)	-31%
2004-2006	3,168,388	1,690,003	53%	496,853	16%	(1,193,149)	-38%
2005-2007	3,132,559	2,003,554	64%	1,303,252	42%	(700,301)	-22%
2006-2008	3,205,646	2,548,310	79%	1,478,227	46%	(1,070,083)	-33%
2007-2009	2,961,924	2,704,150	91%	1,658,514	56%	(1,045,635)	-35%

Oklahoma Gas and Electric Company
Account 364 Poles, Towers, and Fixtures
Net Salvage Using Annual Inflation Rate of 2%

Year	Regular	Cost of Removal		Gross Salvage		Net Salvage	
	Retirements	Amount	Percent	Amount	Percent	Amount	Percent
A	B	C	D=C/B	E	F=E/B	G=E-C	H=G/B
2008-2010	3,260,747	2,833,824	87%	1,039,771	32%	(1,794,053)	-55%
2009-2011	3,429,197	2,766,672	81%	1,121,388	33%	(1,645,284)	-48%
2010-2012	3,510,820	2,820,995	80%	1,047,236	30%	(1,773,758)	-51%
2011-2013	3,608,297	2,950,585	82%	990,459	27%	(1,960,126)	-54%
2012-2014	3,947,429	2,779,898	70%	1,005,543	25%	(1,774,355)	-45%
2013-2015	3,981,912	3,061,882	77%	1,217,671	31%	(1,844,211)	-46%
2014-2016	3,922,813	2,962,927	76%	1,277,925	33%	(1,685,002)	-43%

Five-Year Average

2012-2016	3,736,927	2,994,994	80%	1,149,441	31%	(1,845,553)	-49%
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Sources:

Table 24 of CPI Detailed Report published by U.S. Bureau of Labor Statistics
 (CPI-U current standard reference base period is 1982-1984=100)

Federal Open Market Committee January 30, 2018

“Statement of Longer-Run Goals and Monetary Policy Strategy.”

Page VIII-44 of Direct Exhibit JJS-2

OGE Response to AG 3-7

1 just wanted to start off by looking at your -- you provided
2 your qualifications in your direct testimony in TNM-1. So, I
3 note -- noted in this case, you -- you -- as you stated, you've
4 filed testimony in a number of different -- several different
5 areas, correct?

6 MR. NORMAND: That's correct.

7 MR. COHEN: Okay. And in your -- looking at your
8 experience over the course of the years, you've been doing
9 regulatory work. You've also worked in a number of different
10 areas. Is that correct?

11 MR. NORMAND: That is correct.

12 MR. COHEN: Okay. Cost of service studies and power
13 loss studies, correct?

14 MR. NORMAND: That's correct.

15 MR. COHEN: Okay. And on page three, you listed
16 depreciation studies you participated in, and I think there are
17 roughly about 20 companies noted. Have you done depreciation
18 studies in -- in multiple cases related to those companies?

19 MR. NORMAND: That's correct. I've done several for
20 some of these companies.

21 MR. COHEN: How -- how many depreciation studies have
22 you done totally would you say over your career?

23 MR. NORMAND: I've been involved with depreciation
24 approximately 20 years, and I've been involved with probably
25 50.

1 212 percent was what -- what I was referring to.

2 MR. TAYLOR: I -- I think he's -- he's providing that
3 answer and giving you the appropriate context, so he should be
4 allowed to finish his answer.

5 MR. COHEN: It's a percentage for a different
6 account, but go ahead.

7 MR. NORMAND: You want me to finish this -- this
8 account.

9 MR. COHEN: Go ahead.

10 MR. NORMAND: Okay, so if you look at the last three
11 numbers, 2016, '15, and '14, those averages 230 percent. And
12 as I was saying, that's referencing retired plan, which is old,
13 against current cost. So that gives you a number, and you say,
14 well, I have to adjust that number because I can't really use
15 these numbers are very large. So, for this account, I -- I
16 look more at the five-year average on the right, and what I did
17 is I took 50 percent -- roughly 50 percent, and my
18 recommendation for this account was a 30 percent net salvage.
19 And so, what happens is I tried to discount the huge, large
20 numbers to the left, but at the same time, you have to come up
21 with a net salvage that reflects, as best you can, the
22 information you have, while at the same time trying to remove a
23 lot of the inflation factor, but retaining some of the
24 inflation. So, the 30 percent, what I typically do is look at
25 the five-year groupings on the right, and the last three years,

1 and I will try to make recommendations that are between a third
2 to a half of what I see. That typically will eliminate most of
3 the inflation. And so that -- that's my discussion of this
4 account.

5 MR. COHEN: Okay. So, let's go over to 380 if we
6 can.

7 MR. NORMAND: Okay.

8 MR. COHEN: And this is the distribution services.
9 So, for 2016, let me just go through the numbers here.

10 MR. TAYLOR: Which page are you on, Chuck?

11 MR. COHEN: This is page four of seven. It's the
12 next one of these. So, you have the cost to retire net
13 salvage, -560,648. That was a historical company number,
14 correct?

15 MR. NORMAND: That was the number associated with
16 these retirements, which is the first line number.

17 MR. COHEN: Okay. The -- the removal cost?

18 MR. NORMAND: Yes. The cost to retire is -- is a
19 positive number, but since it's -- it's -- what you do is you
20 subtract it, so it becomes a negative. So, what you have
21 basically -- I retired \$263,517 of services, and then that cost
22 me \$560,649 to retire those services. So essentially, you
23 divide one by the -- the other and you get 212,076 negative.

24 MR. COHEN: And the 566,049, that was the cost in
25 2016 to retire that plant?

1 testified and companies that you've testified for. I guess
2 first before we even get into that, your -- your method of
3 calculating these depreciation rates, that's what's considered
4 a very traditional method, correct?

5 MR. NORMAND: That's correct.

6 MR. TAYLOR: And in your experience in having
7 provided these studies before having testified, is it your
8 experience that your traditional method is a widely accepted
9 one?

10 MR. NORMAND: Yes, it is.

11 MR. TAYLOR: And in your recollection about -- well,
12 actually scratch that. I think you also discussed, or you took
13 a question about your method and referencing to retirement?

14 MR. NORMAND: Yes.

15 MR. TAYLOR: And I think that you discussed why you
16 do it. What is the impact of failing to do that?

17 MR. NORMAND: Well, if you don't reference -- when --
18 when you reference -- the cost of (inaudible) to retirement,
19 and then you adjust your calculated results down to reduce the
20 -- the impact of inflation, what you at least want to do is to
21 have some level of inflation because, as I said earlier, if you
22 don't do that, what you're going to do is you're not going to
23 recover your cost because, again, the Commission will approve
24 accrual rates that will probably be in place six to eight
25 years.

Attorney General of Oklahoma
Data Request AG-20
Cause No. PUD 201700496

- 20-1 Please refer to pages 4 through 7 of Exhibit JTK-1, attached to the direct testimony of Jeffrey T. Kopp. The pages state that the Generation Step-Up (“GSU”) transformers of Mustang Units 1 and 2 have been removed from the site.**
- a) Where are the Mustang Unit 1 and Unit 2 GSU transformers now being used?
 - b) What were the original installation years at the Mustang 1 and Mustang 2 locations of the Mustang Unit 1 and Mustang Unit 2 GSU transformers, respectively?
 - c) Please provide the dollar amount of gross salvage that has been recorded for each of the Mustang Unit 1 GSU and the Mustang Unit 2 GSU when they were retired from the Mustang 1 and Mustang 2 locations, respectively.
 - d) Please provide the dollar amount of Cost of Removal that has been recorded for each of the Mustang Unit 1 GSU and the Mustang Unit 2 GSU when they were retired from the Mustang 1 and Mustang 2 locations, respectively.
 - e) Please provide the amount of net salvage that has been recorded for each of the Mustang Unit 1 GSU and the Mustang Unit 2 GSU when they were retired from the Mustang 1 and Mustang 2 locations, respectively.

Response*:

- a. See AG 16-10.
- b. Both were installed in the year 2000
- c. Mustang 1 and 2 were transferred to Mustang Energy Center CT Units 6 and 7. They were not retired. The reason that Exhibit JTK-1, direct testimony of Jeffrey T. Kopp states that the GSU were removed from the site is because at the time of the Environmental Study, these GSU transformers were off site being refurbished. Upon refurbishment they were returned to the Plant and installed at Mustang Units 6 and 7.
- d. See response in c) above
- e. See response in c) above

Response provided by:	<u>Carla Chupik</u>
Response provided on:	<u>April 13, 2018</u>
Contact & Phone No:	<u>Jason Bailey 405-553-3406</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Attorney General
Data Request AG-7
Cause No. PUD 201700496

7-10 Please provide the total balance included in rate base in OGE's filing for Mustang Units 1, 2, 3, and 4, separately, for each of the following: gross plant, accumulated depreciation, and accumulated deferred income tax. Please explain the effects of federal tax reform on the accumulated deferred income tax balance for each unit, if any.

Response*:

Approximately \$5.7 million of Accumulated Depreciation accrued for removal costs associated with Mustang Units 1 through 4 is included in rate base in OG&E's filing. There are no other balances included in rate base in OG&E's filing for Mustang Units 1, 2, 3, and 4. OG&E's filing includes pro forma rate base as of March 31, 2018. As of December 31, 2017, Mustang Units 1 through 4 had been retired.

Refer to the graphic, attached as **AG 7-10_Att1**.

Prior to retirement, Mustang Units 1 through 4 were classified within the FERC uniform system of accounts as Production Plant — Steam Production. At the time each Mustang unit was retired, any net remaining balances were either reassigned to another unit at the Mustang site or accumulated depreciation was reallocated from the remaining Steam Production Plant functional group. For example, common plant for the Mustang facility was originally capitalized as part of Unit 1, the first unit on that site. When that unit was retired the remaining net balance was transferred to Units 3 and 4. When Units 3 and 4 were retired the common plant was transferred to Unit 6 and 8 at the Mustang location. Please see attachment **AG 7-10_Att2**, specifically the "PI Tsfs by FERC" tab. Mustang 3 and 4 were steam turbine plants and were part of the Steam Production plant functional group. Approximately \$8.3 million of accumulated depreciation within the Steam Production function was moved to Mustang 3 and 4. Please see attachment **AG 7-10_Att2**, specifically the "SO AD and Removal by FERC" tab. Approximately \$5.7 million of accumulated depreciation that had been accrued for removal remains for Mustang Units 1 through 4. Please see the attachment **AG 7-10_Att2** for deferred tax calculations on the "SO AD and Removal by FERC" tab.

Electric Plant Chart of Accounts 18 CFR Part 101

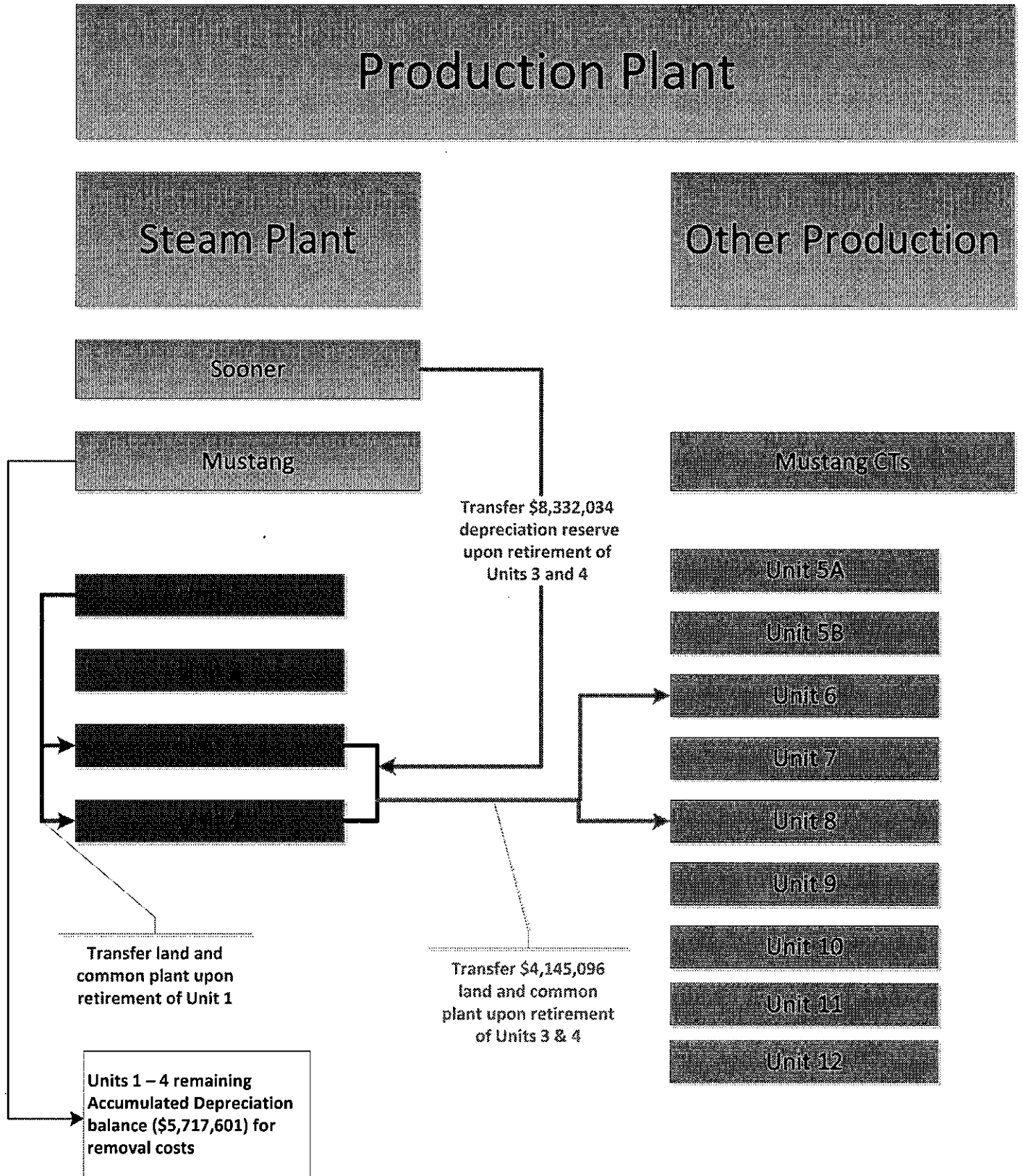
2. PRODUCTION PLANT

A. STEAM PRODUCTION

- 310 Land and Land Rights
- 311 Structures and Improvements
- 312 Boiler Plant Equipment
- 313 Engines and Engine – Driven Generators
- 314 Turbogenerator Unit
- 315 Accessory Electric Equipment
- 316 Miscellaneous Power Plant Equipment
- 317 Asset Retirement Costs for Steam Production Plant

Response provided by: Jason Bailey
Response provided on: February 20, 2018
Contact & Phone No: Jason Bailey 405-557-3406

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.



Attorney General of Oklahoma
Data Request AG-19
Cause No. PUD 201700496

19-20 Please refer to OGE's response to AG-OGE-7-10, including its attachment. The attachment shows that, upon the retirement of Mustang Units 3 and 4, \$4,145,096 of land and common equipment was transferred from Mustang Units 3 and 4 to certain Mustang CT units. Please provide a schedule itemizing the transfer amount by FERC Account—for example, by Account 310.1 (if any), 310.2 (if any), etc. If the schedule does not clarify the exact amount of land included in the transaction, as opposed to common equipment, please also specify the amount of the transfer related only to land rather than common equipment.

Response*: See the attachment in the Company's response to AG 7-10 that provides a schedule itemizing the transfer amount of \$4,145,096 by FERC account. The land amount (340.100) is broken out in the attachment. The \$101,936 of Land in 340.100 represents only land, no equipment.

Response provided by: Carla Chupik
Response provided on: April 12, 2018
Contact & Phone No: Jason Bailey 405-553-3406

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Attorney General of Oklahoma
Data Request AG-16
Cause No. PUD 201700496

16-10 Please refer to the responses to AG-OGE-16-8 and AG-OGE-16-9. For each of the GSU transformers referenced in these responses, please state where the GSU transformer is currently physically located and what it is being used for. If OGE no longer owns or possesses a certain GSU transformer, please explain the disposition of the GSU transformer.

Response*: Please see attachment AG 16-10_Att.

Response provided by: Carla Chupik
Response provided on: March 29, 2018
Contact & Phone No: Jason Bailey 405-553-3406

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

AG 16-10 Data Request Response

Unit	# of GSU's prior to retirement	Current physical location of GSU	What GSU is currently being used for	Explain disposition of GSU
Mustang Unit 1	1	Mustang Energy Center	MT CT Unit 6	Refurbish and reuse of Mustang Unit 1 and Mustang Unit 2 GSUs saved customers approximately \$1 Million as compared to new transformers
Mustang Unit 2	1	Mustang Energy Center	MT CT Unit 7	Refurbish and reuse of Mustang Unit 1 and Mustang Unit 2 GSUs saved customers approximately \$1 Million as compared to new transformers
Mustang Unit 3	1	Mustang Power Plant	Retired in place awaiting plant demolition.	Will likely be part of demolition net salvage contract for the plant site at a future date
Mustang Unit 4	1	Mustang Power Plant	Retired in place awaiting plant demolition.	Will likely be part of demolition net salvage contract for the plant site at a future date
Seminole CT Unit	0	Seminole Power Plant	Seminole GT1 fed its electrical outlet into the station's reserve auxiliary transformer. While the combustion turbine retired the reserve auxiliary transformer remains in service	N/A
Enid Unit 1	0.25	Removed	Removed as part of demolition net salvage contract	Removed as part of demolition net salvage contract
Enid Unit 2	0.25	Removed	Removed as part of demolition net salvage contract	Removed as part of demolition net salvage contract
Enid Unit 3	0.25	Removed	Removed as part of demolition net salvage contract	Removed as part of demolition net salvage contract
Enid Unit 4	0.25	Removed	Removed as part of demolition net salvage contract	Removed as part of demolition net salvage contract
Woodward Unit	1	Removed	Removed as part of demolition net salvage contract	Removed as part of demolition net salvage contract