STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A MULTI-STEP RATE IMPLEMENTATION OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE, AND APPROVAL OF REGULATORY ASSET TREATMENT UPON RETIREMENT OF THE COMPANY'S LAST COAL-FIRED STEAM GENERATION PLANT; (4) APPROVAL OF AN ADJUSTMENT TO THE COMPANY'S FAC RIDER TO TRACK COAL INVENTORY BALANCES; AND (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING AUTHORITY TO: (A) DEFER TO A REGULATORY ASSET EXPENSES ASSOCIATED WITH THE EDWARDSPORT CARBON CAPTURE AND SEQUESTRATION STUDY, (B) DEFER TO A REGULATORY ASSET COSTS INCURRED TO ACHIEVE ORGANIZATIONAL SAVINGS, AND (C) DEFER TO A REGULATORY ASSET OR LIABILITY, AS APPLICABLE, ALL CALCULATED INCOME TAX DIFFERENCES RESULTING FROM FUTURE CHANGES IN INCOME TAX RATES.	)	**CAUSE NO. 46038**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
PUBLIC'S EXHIBIT NO. 9
TESTIMONY OF OUCC WITNESS
DAVID J. GARRETT

July 11, 2024

Respectfully submitted,

Thomas R. Harper
Atty. No. 16735-53
Deputy Consumer Counselor

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APPENDICES

I. INTRODUCTION

Q. State your name and occupation.

A. My name is David J. Garrett. I am a consultant specializing in public utility regulation. I am the managing member of Resolve Utility Consulting, PLLC. I focus my practice on the primary capital recovery mechanisms for public utility companies: cost of capital and depreciation.

Q. Summarize your educational background and professional experience.

A. I received a B.B.A. degree with a major in Finance, an M.B.A. degree, and a Juris Doctor degree from the University of Oklahoma. I worked in private legal practice for several years before accepting a position as assistant general counsel at the Oklahoma Corporation Commission in 2011, where I worked in the Office of General Counsel in regulatory proceedings. In 2012, I began working for the Public Utility Division as a regulatory analyst providing testimony in regulatory proceedings. In 2016 I formed Resolve Utility Consulting, PLLC, where I have represented various consumer groups and state agencies in utility regulatory proceedings, primarily in the areas of cost of capital and depreciation. I am a Certified Depreciation Professional with the Society of Depreciation Professionals. I am also a Certified Rate of Return Analyst with the Society of Utility and Regulatory Financial Analysts. A more complete description of my qualifications and regulatory experience is included in my curriculum vitae.[1]

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[1] Attachment DJG-2-20.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Indiana Office of Utility Consumer Counselor ("OUCC").

Q. Describe the scope and organization of your testimony.

A. My direct testimony here addresses the depreciation rates Duke Energy Indiana, LLC ("Duke" or the "Company") proposed, which are based on the depreciation study Company witness John Spanos sponsored. I address Mr. Spanos's testimony and depreciation study (Petitioner's Exhibit 12), as well as the testimony and exhibits of Company witness Jeffrey Kopp (Petitioner's Exhibit 11), who sponsors the Company's demolition studies. The demolition cost estimates Mr. Kopp proposed impact the terminal net salvage and depreciation rates for Duke's production plants proposed by Mr. Spanos.

II. EXECUTIVE SUMMARY

Q. Summarize the key points of your testimony.

A. Duke is proposing a substantial increase in its annual depreciation accrual in the amount of $260 million, which represents an annual increase of 46%.[2] The Company's depreciation study sponsored by Mr. Spanos contains several unreasonable assumptions and errors that result in excessively high proposed depreciation rates and expense. In my testimony, I propose several reasonable adjustments the Commission should consider that would result in more reasonable depreciation rates. The following table summarizes the current and proposed depreciation accrual amounts.[3]

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[2] *See* Attachment DJG-2-1.

[3] Attachments DJG-2-1, 2-2, and 2-3; *see also* Attachment DJG-2-17 for remaining life calculations.

Figure 1:
Primary Recommendation – ALG Procedure

Plant Function	Current Accrual	DEI Proposed Accrual	OUCC Proposed Accrual	OUCC Adjustment
Production	$ 387,052,960	$ 601,376,151	$ 506,676,497	$ (94,699,654)
Transmission	48,853,050	59,918,194	55,572,414	(4,345,780)
Distribution	103,511,101	132,474,796	109,181,746	(23,293,050)
General	32,573,358	38,969,644	38,579,317	(390,327)
Total Plant Studied	**$ 571,990,469**	**$ 832,738,785**	**$ 710,009,975**	**$ (122,728,810)**

As shown in Figure 1, the OUCC's proposed depreciation rates would reduce the Company's proposed depreciation accrual by $123 million, when applied to plant as of June 30, 2023.[4] As also shown in Figure 1, adopting the OUCC's proposed adjustments would increase the current annual depreciation accrual in the amount of $138 million.

Q. Summarize the primary factors driving the OUCC's depreciation rate adjustments.

A. The OUCC's recommended depreciation rate adjustments are based on several issues, including: (1) removing indirect costs and contingency costs from Duke's decommissioning cost estimates; (2) removing the annual escalation rate from Duke's present value decommissioning cost estimates; and (3) adjusting the Company's proposed service lives for several of Duke's transmission and distribution accounts. The estimated impact of these issues on the OUCC's proposed depreciation accrual adjustment is summarized in the table below.

[4] For the OUCC's adjustment to depreciation expense, please see the testimony and attachments of OUCC witness Mark E. Garrett.

Figure 2:
Broad Issue Impacts

	Issue	Impact
1.	Remove indirect and contingency costs	$11 million
3.	Remove annual escalation rate	$84 million
3.	Adjust service lives	$18 million
4.	Apply gradualisms to net salvage rate increases	$10 million
	Total	**$123 million**

Each of these issues will be discussed in more detail in my testimony.

Q. Describe why it is important not to overestimate depreciation rates.

A. Under the rate-base rate of return model, the utility is allowed to recover the original cost of its prudent investments required to provide service. Depreciation systems are designed to allocate those costs in a systematic and rational manner – specifically, over the service lives of the utility's assets. If depreciation rates are overestimated (i.e., service lives are underestimated), it may unintentionally incent economic inefficiency. When an asset is fully depreciated and no longer in rate base, but still used by a utility, a utility may be incented to retire and replace the asset to increase rate base, even though the retired asset may not have reached the end of its economic useful life. If, on the other hand, an asset must be retired before it is fully depreciated, there are regulatory mechanisms that can ensure the utility fully recovers its prudent investment in the retired asset. Thus, in my opinion, it is preferable for regulators to ensure that assets are not depreciated before the end of their economic useful lives.

Q. Please state your recommendation to the Commission.

A. I recommend the Commission adopt the depreciation rates I propose as listed in Attachment DJG-2-3.

III. DEPRECIATION STANDARDS AND SYSTEMS

Q. Discuss the standard by which regulated utilities are allowed to recover depreciation expense.

A. In *Lindheimer v. Illinois Bell Telephone Co.*, the U.S. Supreme Court stated that "depreciation is the loss, not restored by current maintenance, which is due to all the factors causing the ultimate retirement of the property. These factors embrace wear and tear, decay, inadequacy, and obsolescence."[5] The *Lindheimer* Court also recognized that the original cost of plant assets, rather than present value or some other measure, is the proper basis for calculating depreciation expense. Moreover, the *Lindheimer* Court found:

> [T]he company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion.[6]

Thus, the Commission must ultimately determine if Duke has met its burden of proof by making a convincing showing that its proposed depreciation rates are not excessive.

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[5] *Lindheimer v. Illinois Bell Tel. Co.*, 292 U.S. 151, 167 (1934).

[6] *Id*. at 169.

Q. Should depreciation represent an allocated cost of capital to operation, rather than a mechanism to determine loss of value?

A. Yes. While the *Lindheimer* case and other early literature recognized depreciation as a necessary expense, the language indicated that depreciation was primarily a mechanism to determine loss of value.[7] Adoption of this "value concept" requires annual appraisals of extensive utility plant and is, thus, not practical in this context. Rather, the "cost allocation concept" recognizes depreciation is a cost of providing service, and that in addition to receiving a "return on" invested capital through the allowed rate of return, a utility should also receive a "return of" its invested capital in the form of recovered depreciation expense. The cost allocation concept also satisfies several fundamental accounting principles, including verifiability, neutrality, and the matching principle.[8] The definition of "depreciation accounting" published by the American Institute of Certified Public Accountants ("AICPA") properly reflects the cost allocation concept:

> Depreciation accounting is a system of accounting that aims to distribute cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation.[9]

Thus, the concept of depreciation as "the allocation of cost has proven to be the most useful and most widely used concept."[10]

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[7] *See* Frank K. Wolf & W. Chester Fitch, *Depreciation Systems* 71 (Iowa State University Press 1994).

[8] National Association of Regulatory Utility Commissioners, *Public Utility Depreciation Practices* 12 (NARUC 1996).

[9] American Institute of Accountants, *Accounting Terminology Bulletins Number 1: Review and Résumé* 25 (American Institute of Accountants 1953).

[10] Wolf *supra* n. 7, at 73.

Q. Discuss the definition and general purpose of a depreciation system, as well as the specific depreciation system you employed for this project.

A. The legal standards set forth above do not mandate a specific procedure for conducting depreciation analysis. These standards, however, direct that analysts use a system for estimating depreciation rates that will result in the "systematic and rational" allocation of capital recovery for the utility. Over the years, analysts have developed "depreciation systems" designed to analyze grouped property in accordance with this standard. A depreciation system may be defined by several primary parameters: 1) a <u>method</u> of allocation; 2) a <u>procedure</u> for applying the method of allocation; 3) a <u>technique</u> of applying the depreciation rate; and 4) a <u>model</u> for analyzing the characteristics of vintage property groups.[11] In this case, I used the straight-line method, the average life procedure, the remaining life technique, and the broad group model; this system would be denoted as an "SL-AL-RL-BG" system. This depreciation system conforms to the legal standards set forth above and is commonly used by depreciation analysts in regulatory proceedings. I provide a more detailed discussion of depreciation system parameters, theories, and equations in Appendix A.

Q. Are you and Mr. Spanos essentially using the same depreciation system to conduct your analyses?

A. Yes. Mr. Spanos and I are essentially using the same depreciation system. Thus, the difference in our positions stems from our different opinions regarding production net salvage rates, interim retirements, and mass property service life estimates.

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[11] *See* Wolf *supra* n. 7, at 70, 140.

IV. PRODUCTION PLANT ANALYSIS

Q. Please summarize your proposed adjustments to Duke's production plant depreciation rates.

A. The assets within a production plant are often considered as "life span" property, in which the assets comprising the life span unit are projected to retirement concurrently, regardless of their individual ages or remaining economic lives at the time of the unit's retirement. I propose several adjustments which impact Duke's proposed depreciation rates for its production plant accounts, including the removal of contingency and indirect costs from the Company's decommissioning cost estimates and the removal of the annual escalation rate Mr. Spanos applied to Duke's present value demolition cost estimates. These issues are discussed below.

A. Contingency and Indirect Costs

Q. Please describe how the contingency and indirect costs included in Duke's decommissioning studies impact the Company's proposed depreciation rates.

A. The decommissioning cost estimates Mr. Kopp proposed include contingency costs and indirect cost estimates and assumptions for each of Duke's production plants. Mr. Spanos incorporated these cost estimates in his calculation of Duke's production plant depreciation rates. Specifically, the decommissioning cost estimates impact the terminal net salvage rate component of the Company's production plant depreciation rates.

Q. Did Mr. Kopp provide any convincing support for the contingency and indirect costs included in the decommissioning studies he sponsors?

A. No. The decommissioning studies include arbitrary percentages of 10% for indirect costs and 20% for contingency costs for each production unit included in the decommissioning studies.[12] According to Mr. Kopp, "indirect costs were added to cover costs incurred by the Company in executing the projects, and contingency was added to account for unknown, but reasonably expected to be incurred costs."[13]

Q. What is the total amount of contingency and indirect costs included in the Company's proposed depreciation accrual?

A. The total amount of indirect and contingency costs included in the decommissioning studies that ultimately impact terminal net salvage and depreciation rates is more than $130 million. The amount these costs would impact the annual depreciation accrual is approximately $10 million.[14]

Q. Do you believe the Company has adequately supported the inclusion of these contingency costs in rates?

A. No. Regarding contingency costs, it is undisputed that contingency costs are unknown, unspecified, and related to uncertainties. These aspects of contingency costs actually better support why they should be excluded for ratemaking purposes. Under basic ratemaking principles, current customers should not be charged for future costs potentially occurring decades into the future that are "unknown" by definition. Even if the plant demolitions were to occur tomorrow, the contingency costs would still be unknown by definition. The fact that contingency costs are to occur up to several decades from now exacerbates this

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[12] Attachment 11-A (JTK).

[13] Petitioner's Exhibits 11, Direct Testimony of Jeffrey T. Kopp, p. 7, lines 13-15.

[14] *See* Attachment DJG-2-6.

problem, especially from a ratemaking perspective. Furthermore, the contingency costs are clearly arbitrary and not tied to any specific cost metric.

Q. Does recovery of contingency costs shift risks from shareholders to ratepayers?

A. Yes. In financial modeling, we assume that investors seek the maximum return on investment for a given level of risk. In the competitive market, competition establishes a risk-return equilibrium. Under the regulatory model, however, investors can achieve higher returns given the level of risk, when they can convince regulators to approve mechanisms or costs that reduce risk, while still being awarded returns on equity that are above market-based cost of equity (these concepts are discussed in more detail in Public's Exhibit No. 8, my rate of return testimony). Thus, it is not surprising the Company would want approval of an uncertain and unknown future cost – it would increase cash flow and reduce risk.

Q. Can you think of a cost in any other area of a rate case in which the utility can increase such cost by 20% for no other reason than the cost is unknown?

A. No. By definition, all projected, future costs are uncertain, but I cannot think of any other cost in a rate case in which regulators would allow the utility to arbitrarily increase such a cost by 20% and expect recovery of it.

Q. Could the same argument in support of increased contingency costs be used to support decreased contingency costs?

A. Yes. If one were to approach this issue objectively, the same arguments used in support of increased contingency costs could be used to support decreased contingency costs. In other words, if a future cost is unknown (which demolition costs are), then it would be just as fair to ratepayers to decrease such cost estimates to account for "unknown" factors as it would be to shareholders to increase such costs. However, I think the most fair and reasonable approach is to disallow contingency factors in either direction.

Q. Has the Commission allowed demolition contingency costs in prior rate proceedings?

A. Yes. However, the Commission is not bound by its prior decisions on this issue. In my opinion, charging customers 20% more than the estimated base demolition costs for a cost that is unknown on its face is poor ratemaking policy. I am not aware of comparable cost estimates in a rate proceeding where it is considered acceptable to significantly increase the cost by an arbitrary percentage on the sole basis that the cost is "unknown." The Commission should, accordingly, reconsider its stance and reject the proposed contingency cost adder to Duke's base demolition cost estimates or reduce the proposed percentage increase being added. The Commission approved including contingency in two relatively recent litigated rate cases, Cause No. 45235 (I&M) and Cause No. 45253 (Duke). In both cases, the OUCC advocated for removing contingency from the decommissioning study. In Cause No. 45235 (I&M), the rebuttal to the OUCC's position mainly indicated that including contingency within the depreciation study is Commission precedent.[15] In Cause No. 45253 (Duke), in his rebuttal testimony, Mr. Spanos refuted a proposal which is not an issue here and also relied solely on the premise that this inclusion follows Commission precedent.[16] In both cases, the Commission approved including contingency.[17] What was

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[15] Cause No. 45235, Rebuttal Testimony of Jason Cash, p. 7, line 13 to p. 8, line 11 (September 17, 2019).

[16] Cause No. 45253, Rebuttal Testimony of John Spanos, p. 31, line 1 to p. 36, line 10 (December 4, 2019).

[17] Cause No. 45235, Final Order at 32 (March 11, 2020); Cause No. 45253, Final Order at 91 (June 29, 2020).

not included, either in rebuttal or in the Commission's decision, was a substantive response to the OUCC's arguments against including an arbitrary percentage denoted as contingency. The Commission found in Cause No. 45235 that I was "asking the Commission to disregard our prior acceptance of contingency."[18] That is what I am again asking in this case in the absence of Duke having shown its propriety, its fairness to ratepayers, and that 20% is other than arbitrary. As the Commission reconsidered its position on ELG in Cause No. 45235, the Commission is asked to conduct a substantive review of this issue, based on the arguments against this proposal, and reconsider its position on the propriety of a contingency adder in the depreciation study that is actually unknown and uncertain and will shift dollars from current ratepayers for costs Duke may not incur for decades.

Q. Do your proposed net salvage rates exclude the Company's proposed contingency factors?

A. Yes, for the reasons discussed above, my proposed terminal net salvage rates exclude the contingency costs proposed in the Company's demolition studies.[19]

Q. If the Commission rejects your proposal to disallow all contingency costs from the Company's terminal net salvage rate calculations, is there an alternative proposal you urge the Commission to consider?

A. Yes. If the Commission rejects a complete disallowance of contingency costs, I propose the Commission limit the contingency costs at issue to 10%, rather than the 20% the

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[18] Cause No. 45235, Final Order at 32.

[19] See Attachments DJG-2-7 and 2-8.

Company proposed. This approach would help mitigate the excessive and unsupported cost increases otherwise imposed on Duke's ratepayers due to contingency costs.

B. Annual Cost Escalation

Q. Please describe the cost escalation factors the Company applied to its present-value demolition cost estimates.

A. The decommissioning cost estimates Mr. Kopp proposed are stated in present-value dollars. Mr. Spanos applied an annual escalation rate of 2.5% to these costs estimates, which increases the cost estimates for each production facility each year until the facility's projected retirement date.[20]

Q. Is there an error in the depreciation study regarding the calculation of production net salvage rates related to the escalation factors?

A. Yes. In the depreciation study, approximately $92.1 million of "Coal Ash ARO" costs were escalated and double counted. The total decommissioning costs for each of Duke's production facilities are presented in the depreciation study, and there is a separate column for "Coal Ash ARO" costs. These costs are then removed from the total decommissioning cost and recalculated as Total Decommissioning Less PCM" costs. However, instead of using these recalculated amounts (with the ARO costs excluded) to calculate the decommissioning costs ultimately used in net salvage rates, the $92.1 million of ARO costs was not only included, but double counted.[21] That is, the escalated decommissioning costs ultimately used to calculate Duke's production net salvage rates include both the original

[20] Attachment 12-A (JJS), p. 297, Table 3.

[21] *See id*.

coal ash ARO costs ($92.1 million) and the escalated version of those costs ($122.6 million).[22]

Q. Has the Company acknowledged this error?

A. Apparently yes, or at least in part. In a discovery response, Duke acknowledged: "[u]pon review of the depreciation study filed in this proceeding, it appears that the $92.1 million was inadvertently escalated when it was added to the depreciation study. Please refer to page 297 of Attachment 12-A(JJS) for the escalated figure of $122,575,419. Petitioner will correct this in its rebuttal testimony in this proceeding."[23]

Q. Even if the Company corrects this error in its rebuttal testimony, will this resolve your concerns regarding the escalated cost rates?

A. Not likely. Even if the Company provides a correction to the calculation errors in the depreciation study related to the proposed terminal net salvage rates, as long as the net salvage rates include any cost escalation of present-value decommissioning cost estimates, I recommend the Commission reject Duke's proposed net salvage rates. At the very least, the calculation error related to the double counting and escalation of the coal ash ARO costs must be resolved, and thus, the Company's proposed depreciation rates for its production facilities as stated in the depreciation study should not be accepted until corrected.

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[22] *See id*.

[23] Attachment DJG-2-12, Duke's Response to OUCC 24.3.

Q. Are the $92.1 million of Coal Ash ARO costs also removed from net salvage in your depreciation rates for another reason?

A. Yes. As addressed by OUCC witness Cynthia M. Armstrong, the OUCC objects to the recovery of these costs, the separate recovery of which had already been litigated and reversed on appeal in a prior, separate proceeding.

Q. Does the Company's proposal related to escalated demolition costs violate fundamental principles regarding the time value of money?

A. Yes. Current ratepayers should not be charged for a future cost that has not been discounted to present value. The concept of the time value of money is a cornerstone of finance and valuation. For example, as discussed in my rate of return testimony, the Gordon Growth Model (or DCF Model) is one of the most widely used valuation models. This model applies a growth rate to a company's dividends many years into the future; however, that dividend stream is then discounted back to the current year by a discount rate to arrive at the present value of an asset. In contrast to this approach, Duke escalated the present value of its demolition costs decades into the future and is essentially asking current ratepayers to pay the future value of an escalated cost with present-day dollars. This arrangement ignores the time value of money principle and is inappropriate for that reason alone.

V. MASS PROPERTY ANALYSIS

Q. Describe the methodology used to estimate the service lives of grouped depreciable assets.

A. The process used to study industrial property retirement is rooted in the actuarial process used to study human mortality. Just as actuarial analysts study historical human mortality data to predict how long a group of people will live, depreciation analysts study historical plant data to estimate the average lives of property groups. The most common actuarial method used by depreciation analysts is called the "retirement rate method." In the retirement rate method, original property data, including additions, retirements, transfers, and other transactions, are organized by vintage and transaction year.[24] The retirement rate method is ultimately used to develop an "observed life table" ("OLT"), which shows the percentage of property surviving at each age interval. This pattern of property retirement is described as a "survivor curve." The survivor curve derived from the observed life table, however, must be fitted and smoothed with a complete curve to determine the ultimate average life of the group.[25] The most widely used survivor curves for this curve fitting process were developed at Iowa State University in the early 1900s and are commonly known as the "Iowa curves."[26] A more detailed explanation of how the Iowa curves are used in the actuarial analysis of depreciable property is set forth in Appendix C.

Q. Please describe how you statistically analyzed Duke's historical retirement data to determine the most reasonable Iowa curve to apply to each account.

A. I used the aged property data Duke provided to create an OLT for each account. The data points on the OLT can be plotted to form a curve (the "OLT curve"). The OLT curve is not a theoretical curve; rather, it is actual observed data from the Company's records that indicates the rate of retirement for each property group. An OLT curve by itself, however,

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[24] The "vintage" year refers to the year a group of property was placed in service (aka "placement" year). The "transaction" year refers to the accounting year in which a property transaction occurred, such as an addition, retirement, or transfer (aka "experience" year).

[25] *See* Appendix C for a more detailed discussion of the actuarial analysis used to determine the average lives of grouped industrial property.

[26] *See* Appendix B for a more detailed discussion of the Iowa curves.

is rarely a smooth curve, and is often not a complete curve (i.e., it does not end at zero percent surviving). In order to calculate average life (the area under a curve), a complete survivor curve is required. The Iowa curves are empirically derived curves based on the extensive studies of the actual mortality patterns of many different types of industrial property. The curve-fitting process involves selecting the best Iowa curve to fit the OLT curve. This can be accomplished through a combination of visual and mathematical curve-fitting techniques, as well as professional judgment. The first step of my approach to curve-fitting involves visually inspecting the OLT curve for any irregularities. For example, if the "tail" end of the curve is erratic and shows a sharp decline over a short period of time, it may indicate this portion of the data is less reliable, as further discussed below. After inspecting the OLT curve, I use a mathematical curve-fitting technique which, essentially, involves measuring the distance between the OLT curve and the selected Iowa curve to get an objective, mathematical assessment of how well the curve fits. After selecting an Iowa curve, I observe the OLT curve along with the Iowa curve on the same graph to determine how well the curve fits. As part of my analysis, I may repeat this process several times for any given account to ensure the most reasonable Iowa curve is selected.

Q. Do you always select the mathematically best-fitting curve?

A. Not necessarily. Mathematical fitting is an important part of the curve-fitting process because it promotes objective, unbiased results. While mathematical curve-fitting is important, however, it may not always yield the optimum result. For example, if there is insufficient historical data in a particular account and the OLT curve derived from that data is relatively short and flat, the mathematically "best" curve may be one with a very long average life. When there is sufficient data available, though, mathematical curve fitting can be used as part of an objective service life analysis. In the event there is insufficient historical data, or other extenuating circumstances warrant, I use professional judgment and opinion, supported by objective evidence and analysis. Judgment based on speculation is less reliable than mathematical analysis, not more reliable.

Q. Should every portion of the OLT curve be given equal weight?

A. Not necessarily. Many analysts have observed that the points comprising the "tail end" of the OLT curve may often have less analytical value than other portions of the curve. In fact, "[p]oints at the end of the curve are often based on fewer exposures and may be given less weight than points based on larger samples. The weight placed on those points will depend on the size of the exposures."[27] In accordance with this standard, an analyst may decide to truncate the tail end of the OLT curve at a certain percent of initial exposures, such as one percent. Using this approach puts greater emphasis on the most valuable portions of the curve. For my analysis in this case, I not only considered the entirety of the OLT curve, but also conducted further analyses that involved fitting Iowa curves to the most significant part of the OLT curve for certain accounts. I will illustrate an example of this approach in the discussion below.

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[27] Wolf *supra* n. 7, at 46.

Q. Generally, describe the differences between the Company's service life proposals and your service life proposals.

A. For each of the accounts to which I propose adjustments, Duke's proposed average service life, as estimated through an Iowa curve, is too short to provide the most reasonable mortality characteristics of the account. Generally, for the accounts in which I propose a longer service life, that proposal is based on the objective approach of choosing an Iowa curve that provides a better mathematical fit to the observed historical retirement pattern derived from the Company's plant data, and in my professional judgment, there was not a sufficiently objective or reliable basis to deviate too far from the historical retirement pattern.

Q. Please describe why the objective approach to estimating service lives is preferable to one involving more subjectivity.

A. A service life estimate which is overly reliant on subjective elements is effectively lacking evidentiary support. In contrast, my service life proposals are actually based on evidence, i.e., the observed service life of the individual accounts. If a service life is based on a subjective component, that component should be supported by actual evidence. In other words, "judgment" by itself does not represent evidentiary support for a service life estimate.

Q. Please discuss factors that can be considered when estimating service life.

A. NARUC's Public Utility Depreciation Practices sets forth factors that can be considered when estimating service life, including:

1. Observable trends reflected in historical data,
2. Potential changes in the type of property installed,
3. Changes in the physical environment

4. Changes in management requirements,
5. Changes in government requirements, and
6. Obsolescence due to the introduction of new technologies.[28]

Effectively, my analyses of Duke's historical retirement data would incorporate the impact on service life from these factors and other forces of retirement over time. The utilization of Iowa curves provides an objective and accurate basis on which this historical data can be used to project future remaining life.

Q. Did Mr. Spanos specifically discuss these factors and how they impacted his service life estimates?

A. No. Mr. Spanos did not testify regarding which, and to what extent, he considered these factors when making his service life estimates. However, the historical retirement data the Company provided would incorporate all of these factors and their impact upon the retirement rate of the Company's assets over time. In that regard, relying on the actual evidence presented in this case (i.e., the Company's property data) to estimate service life incorporates these factors outlined in the NARUC manual.

Q. Do you incorporate judgment in your service life estimates?

A. Yes. My judgment is based on my experience as a depreciation analyst and my consideration of all the evidence presented in this case related to the Company's proposed depreciation rates. However, I place a greater amount of consideration on the statistical data and analyses rather than judgment; consequently, my service life estimates are based on more concrete evidence, rather than subjective elements. As discussed below in more

[28] National Association of Regulatory Utility Commissioners, Public Utility Depreciation Practices, 1996, p. 129.

detail, the Iowa curves I propose for each account in dispute result in a closer mathematical fit to the Company's historical retirement patterns, and I also check the results visually to determine the best fit.

Q **In support of its service life estimates, did Duke present substantial evidence in addition to the historical plant data for each account?**

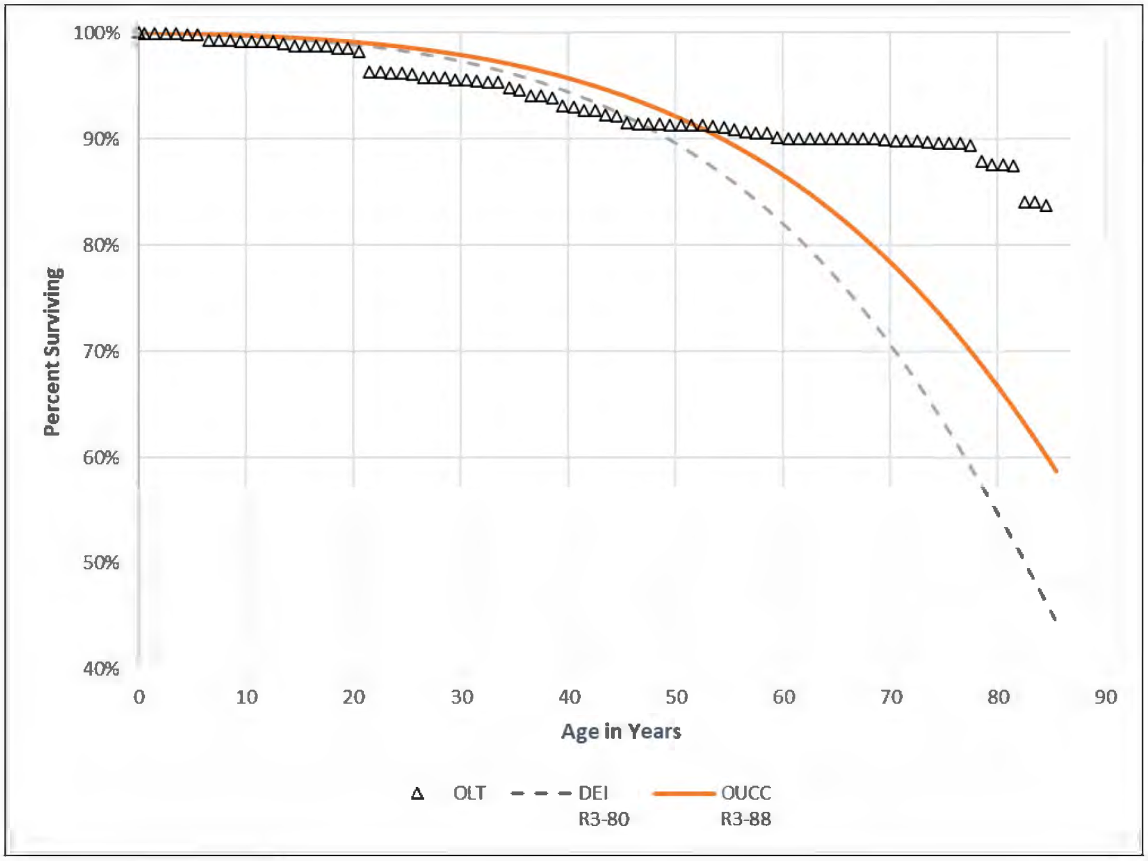
A. No. It appears Duke is relying primarily on its historical retirement data in order to make predictions about the remaining average life for the assets in each account. The Commission should also focus primarily on this historical data and objective Iowa curve fitting when assessing fair and reasonable depreciation rates for Duke. The service lives I propose in this case are based on Iowa curves that provide better mathematical fits to Duke's historical retirement data, and they result in more reasonable service life estimates and depreciation rates for the accounts to which I propose adjustments.

A. Account 354 – Towers and Fixtures

Q. Describe your service life estimate for Account 354 and compare it with the Company's estimate.

A. For Account 354, Mr. Spanos selected the R3-80 curve, and I selected the R3-88 curve. Both of these curves are shown in the following graph with the OLT curve.

Figure 3:
Account 354 – Towers and Fixtures



As shown in the graph, the Iowa curve Mr. Spanos proposed ignores a large portion of the OLT curve and the indicated retirement pattern in this account. Specifically, at age 50 the R3-80 curve selected by Mr. Spanos visibly declines in a way that entirely ignores the retirement pattern observed in the OLT curve. In other words, Mr. Spanos's Iowa curve is not giving enough consideration to the only real evidence presented for this account. In contrast, the Iowa curve I selected results in a good balance between the observed retirement pattern and the likelihood that the retirement rate going forward may increase relative to its rate thus far, causing the OLT curve to decline in the shape of an R3 or similar curve type. In other words, both Iowa curves suggest the future retirement rate will likely be greater than the historical retirement rate, or that the OLT curve will drop relative to its current position, DEI's proposed curve more so than the curve I propose. This account also shows an example of an appropriate use of professional judgment. The Iowa curve I selected is not the best mathematical fit (which would be a much longer Iowa curve), but it does not completely ignore relevant data points that occur after age 50 in the OLT curve. Duke has not offered evidence to support deviating from the observed data in the OLT curve to the extent the Iowa curve proposed by Mr. Spanos does. Mathematical curve fitting can be used to further assess the results. In my professional judgment, the R3-88 curve is the most appropriate for this account.

Q. Does the Iowa curve you selected result in a closer mathematical fit to the OLT curve?

A. Yes. While visual curve-fitting techniques can help an analyst identify the most statistically relevant portions of the OLT curve for this account, mathematical curve-fitting techniques can help determine which of the two Iowa curves provides the better fit. Mathematical curve-fitting essentially involves measuring the distance between the OLT curve and the selected Iowa curve. The best fitting curve is the one that minimizes the distance between the OLT curve and the Iowa curve, thus providing the closest fit. The distance between the curves is calculated using the "sum-of-squared differences" ("SSD") technique. In this account, the total SSD, or distance between the Company's curve and the OLT curve is 1.5459, and the SSD between the R3-88 curve I selected and the OLT curve is 0.5989, which means it results in the closer fit.[29]

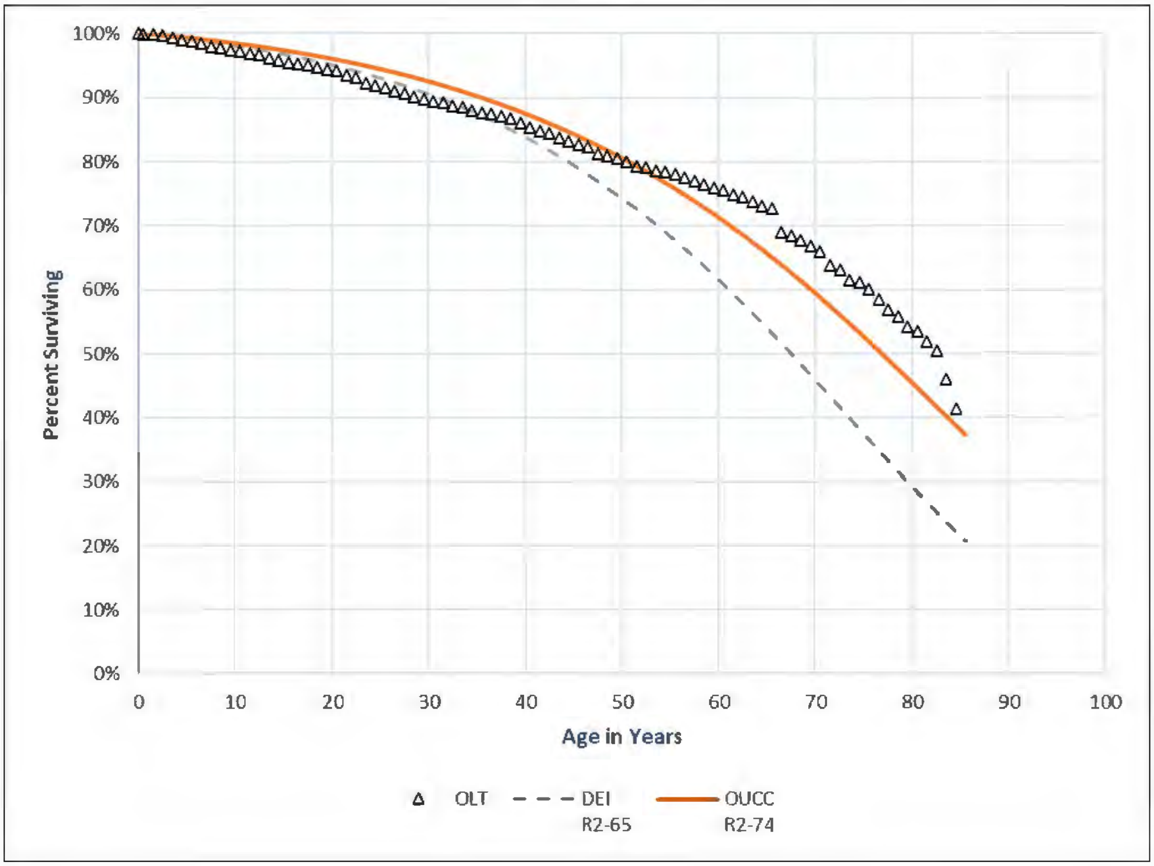
[29] Attachment DJG-2-7.

B. Account 356 – Transmission Overhead Conductors and Devices

1 **Q. Describe your service life estimate for Account 356 and compare it with the**
2 **Company's estimate.**

3 A. Mr. Spanos selected the R2-65 curve for Account 356, and I selected the R2-74 curve.
4 Both of these Iowa curves are shown in the following graph with the OLT curve.

Figure 4:
Account 356 – Transmission Overhead Conductors and Devices



5 As shown in the graph, the Iowa curve Mr. Spanos selected effectively ignores relevant
6 historical data occurring after age 40. As a result, the Iowa curve he proposes understates
7 the average life of the assets in this account based on the only empirical evidence provided

to support the proposed service life. As a result, the depreciation rate Duke proposed for this account is overstated.

Q. Does the Iowa curve you selected result in a closer fit to the OLT curve for this account?

A. Yes. The SSD between the Company's curve and the OLT curve is 1.2277. The SSD between the R2-74 curve I selected and the OLT curve is 0.1459, which means it results in the closer fit.[30]

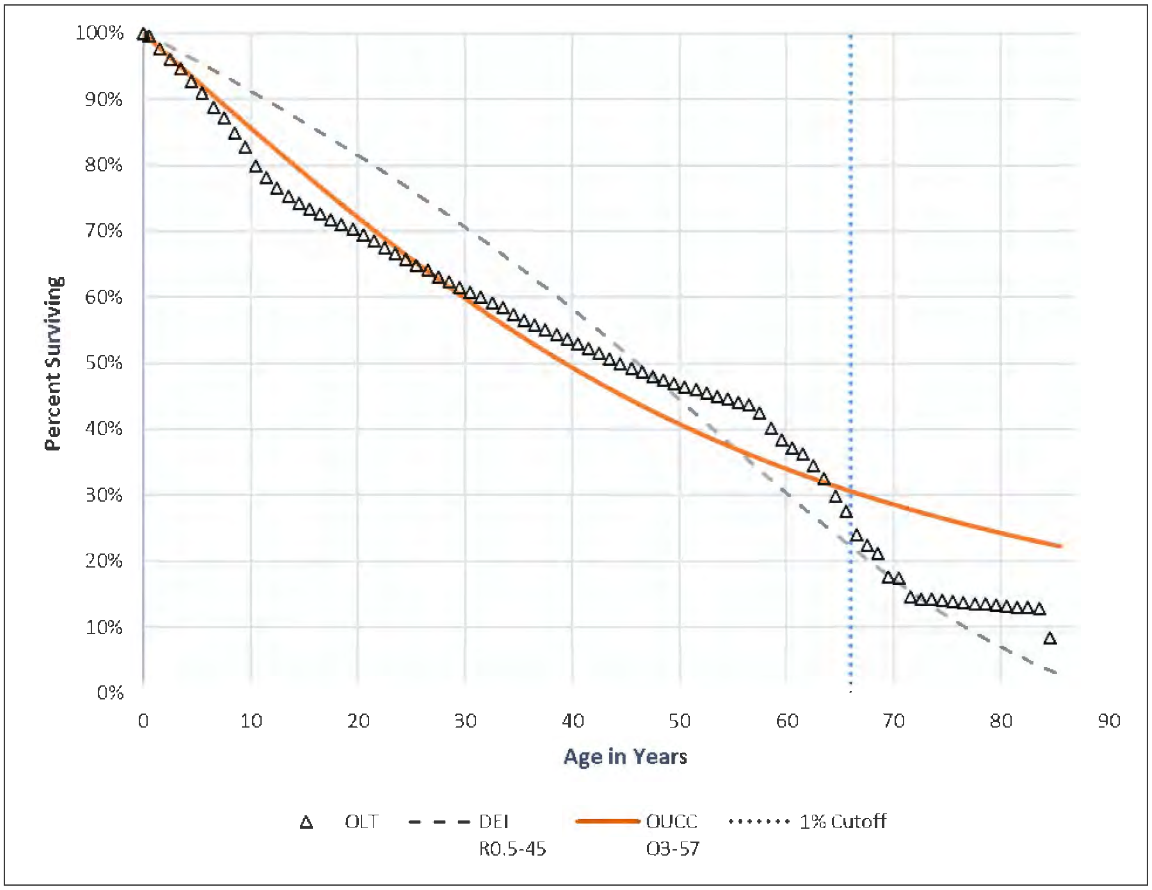
C. Account 365 – Distribution Overhead Conductors and Devices

Q. Describe your service life estimate for Account 365 and compare it with Duke's estimate.

A. For this account, Mr. Spanos selected the R0.5-45 curve, and I selected the O3-57 curve. Both of these curves are shown in the following graph with the OLT curve.

[30] Attachment DJG-2-8.

Figure 5:
Account 365 – Distribution Overhead Conductors and Devices



The vertical dotted line with the graph shows a typical truncation benchmark in which the data points to the right of the truncation line are associated with dollars exposed to retirement that are less than 1% of the total dollars exposed at age zero in this account. From that standpoint, these data points are statistically irrelevant. This is pertinent because the only portion of the OLT curve for this account to which the Iowa curve selected by Mr. Spanos appears to result in a relatively close fit is at the end of the OLT curve – the most statistically irrelevant portion. Although O-shaped curves are less common than R-shaped curves, the OLT curve pattern displayed for this account is more reflective of an O-shaped rather than R-shaped Iowa curve. As shown in the graph, the R-shaped curve proposed by

Mr. Spanos suggests a more convex retirement pattern through ages zero though 40, when the actual retirement pattern is more of a concave pattern. As with other accounts discussed in my testimony, Mr. Spanos did not offer any basis for deviating this far from the historical retirement pattern. Mathematical curve fitting techniques can be used to further assess the results.

Q. Does the Iowa curve you selected for this account result in a closer fit to the OLT curve?

A. Yes. Regardless of whether the entire OLT curve or truncated OLT curve is measured, the Iowa curve I selected results in the closer fit. Specifically, the SSD between the Company's curve and the OLT curve is 0.4578, and the SSD between the O3-57 curve I selected and the OLT curve is 0.3390, which means it results in the closer fit.[31]

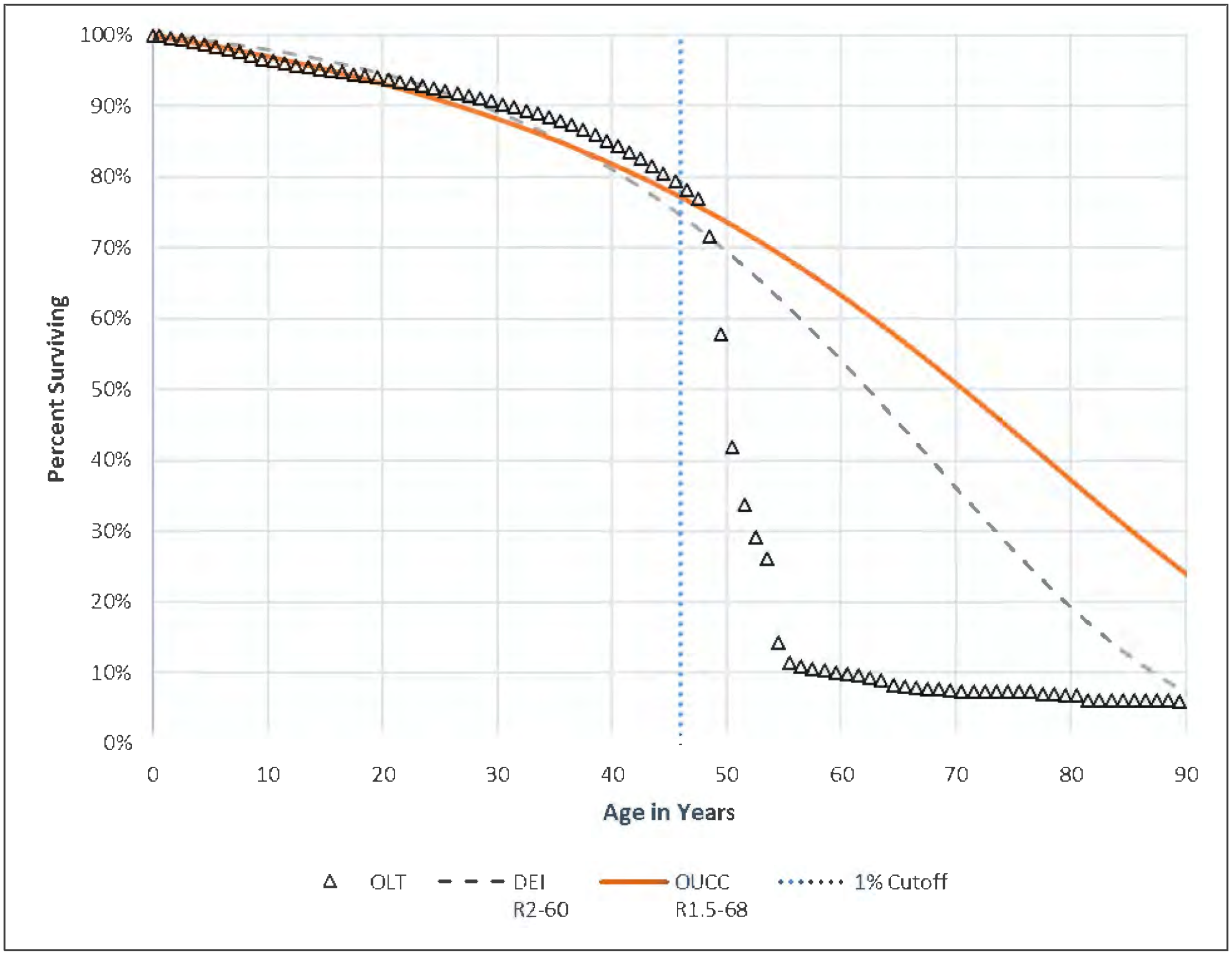
D. Account 367 – Underground Conductors and Devices

Q. Describe your service life estimate for Account 367 and compare it with Duke's estimate.

A. For this account, Mr. Spanos selected the R2-60 curve, and I selected the R1.5-68 curve. Both of these curves are shown in the following graph with the OLT curve.

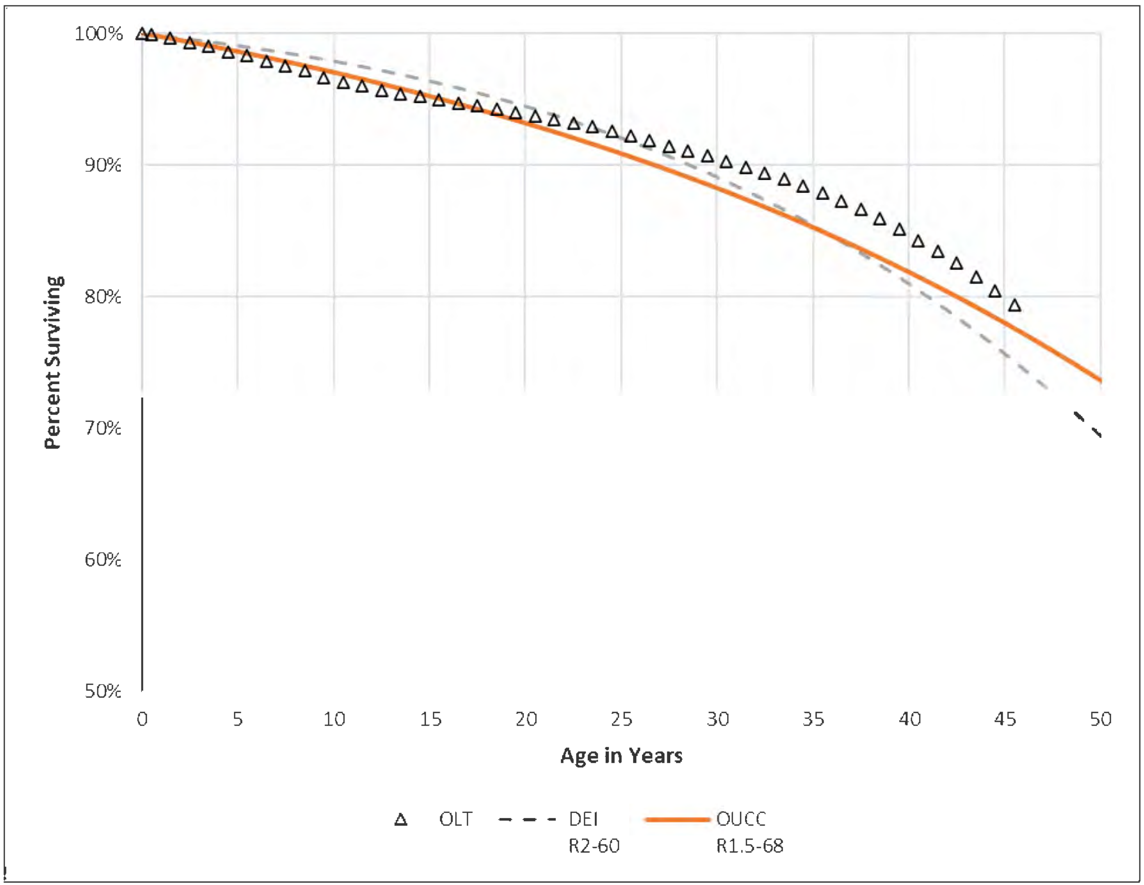
[31] Attachment DJG-2-9.

Figure 6:
Account 367 – Underground Conductors and Devices



The vertical dotted line with the graph shows a typical truncation benchmark in which the data points to the right of the truncation line are associated with dollars exposed to retirement that are less than 1% of the total dollars exposed at age zero in this account. The OLT curve for this account shows why the 1% benchmark is often a good starting point for the truncation line. Here we start to see a sudden and significant drop off in the OLT curve after this truncation point, which is a visual indication that the OLT curve is becoming statistically unreliable. The following graph shows the same information, but the OLT curve is truncated and focused in for more detail.

Figure 7:
Account 367 – Underground Conductors and Devices (Truncated)



When assessing the most relevant portion of the OLT curve, the flatter trajectory and longer average life of the R1.5-68 Iowa curve is more reflective of the retirement rate displayed in the OLT curve. Mathematical curve fitting techniques can be used to further assess the results.

Q. Does the Iowa curve you selected for this account result in a closer fit to the truncated OLT curve?

A. Yes. When measuring the truncated (not entire) OLT curve, the R1.5-68 curve I selected results in the closer fit. Specifically, the SSD between the Company's curve and the truncated OLT curve is 0.0202, and the SSD between the R1.5-68 Iowa curve I selected and the truncated OLT curve is 0.0142, which means it results in the closer fit.[32]

Q. Do your forgoing analyses and recommendations include professional judgment in addition to the objective factors you discussed?

A. Yes. As discussed above, I include both objective and subjective factors in my analyses and recommendations; however, I do give more consideration to the objective factors. In this case, Mr. Spanos's judgment resulted in service life estimates that are too short for the accounts in dispute based on the evidence and other information presented. As a result, the depreciation rates Mr. Spanos proposed for these accounts are unreasonably high.

VI. MASS PROPERTY NET SALVAGE ANALYSIS

Q. Describe the concept of net salvage.

A. If an asset has any value left when it is retired from service, a utility might decide to sell the asset. The proceeds from this transaction are called "gross salvage." The corresponding expense associated with the removal of the asset from service is called the "cost of removal." The term "net salvage" equates to gross salvage less the cost of removal. Often, the net salvage for utility assets is a negative number (or percentage) because the cost of

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[32] Attachment DJG-2-10.

removing the assets from service exceeds any proceeds received from selling the assets. When a negative net salvage rate is applied to an account to calculate the depreciation rate, it results in increasing the total depreciable base to be recovered over a particular period and increases the depreciation rate. Therefore, a greater negative net salvage rate equates to a higher depreciation rate and expense, all else held constant.

Q. Please describe the Company's proposal regarding its net salvage rates for mass property accounts.

A. The Company is proposing significant increases in negative net salvage for several of its mass property accounts. This has an increasing effect on depreciation rates and expense. The net salvage issues discussed above relate to the Company's production plant accounts. The net salvage adjustments discussed here relate to the Company's transmission and distribution accounts.

Q. Did Duke provide evidence to support its proposed increases in negative net salvage rates?

A. Yes. Unlike the accounts discussed above regarding service life, the Company did provide evidence that was generally supportive of its proposed increase in negative net salvage for its mass property accounts. While I agree that a general increase in negative net salvage is warranted at this time, I recommend the Commission adopt a policy that takes a more gradual approach with adopting these increases in order to mitigate the financial impact to customers. I will expand upon this recommendation below

Q. Has there been a trend in increasing negative net salvage in the utility industry?

A. Yes. Negative net salvage rates occur when the cost of removal exceeds the gross salvage of an asset when it is removed from service. Net salvage rates are calculated by considering gross salvage and removal costs as a percentage of the original cost of the assets retired. In other words, salvage and removal costs are based on current dollars, while retirements are based on historical dollars. Increasing labor costs associated with asset removal combined with the fact that original costs remain the same have contributed to increasing negative net salvage over time.

Q. Have other utility commissions expressed concern over increasing negative net salvage rates?

A. Yes. In Pacific Gas and Electric Company's ("PG&E") 2014 rate case, the California commission stated: "We remain concerned with the growing cost burden associated with increasing cost trends for negative net salvage."[33] The California commission also expressed an interest in the ratemaking concept of gradualism:

[33] Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2014-2016, D.14-08-032, p. 597.

> In evaluating whether a proposed increase reflects gradualism, however, we believe the more appropriate measure is how the change affects customers' retail rates. The fact that PG&E previously proposed higher removal costs than adopted has no bearing on how a proposed change would impact current ratepayers. Accordingly, we apply the principle of gradualism based on how a proposed change in estimate compares to adopted costs reflected in current rates, irrespective of what PG&E may have forecasted in an earlier depreciation study.[34]

In PG&E's 2014 rate case, the California Office of Ratepayer Advocates proposed a 25% cap on increased net salvage rates to mitigate sudden increases in net salvage and instead provide for more gradual levels of increases.[35] The California commission ultimately found: "As a general approach, we adopt no more than 25% of PG&E's estimated increases in the accrual provision for removal costs. This limitation tempers the impacts on current ratepayers[.]"[36]

Q. Do you believe it would be appropriate for the Commission to consider a similar approach regarding the Company's proposed net salvage increases?

A. Yes. I recommend the Commission consider gradualism regarding proposed increases to negative net salvage rates. This is a policy that could be reconsidered and applied as necessary on a case-by-case basis, based on the need to mitigate potential cost increases for current customers. Moreover, this approach regarding gradualism will not result in financial harm, nor would it contemplate anything less than full cost recovery for the utility.

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[34] *Id*. at 598.

[35] *Id*. at 592-93.

[36] *Id*. at 602.

Q. Please summarize your proposed net salvage adjustments.

A. I recommend Duke's proposed increases to negative net salvage rates be limited to 25% of the proposed increase in the interest of gradualism. Even if all of the OUCC's proposed adjustments to depreciation rates were adopted, including the mass property net salvage rate adjustment, it would still result in a significant increase to the Company's annual depreciation accrual. Under these circumstances, it is especially pertinent for the Commission to consider gradualism in the interest of fairness and reasonableness. The current and proposed net salvage rates for the accounts at issue are presented in my exhibits.[37]

Q. Does this conclude your depreciation testimony?

A. Yes.

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[37] *See* Attachment DJG-2-3.

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

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David J. Garrett
Resolve Utility Consulting, Inc.
Indiana Office of Utility Consumer Counselor

Cause No. 46038
DEI, LLC

Date: July 11, 2024

Summary Depreciation Accrual Adjustment

Plant Function	Plant 6/30/2023	Current Parameters		Company Position		OUCC Position		OUCC Adjustment	
		Rate	Accrual	Rate	Accrual	Rate	Accrual	Rate	Adjustment
Production	$ 9,265,007,105	4.18%	$ 387,052,960	6.49%	$ 601,376,151	5.47%	$ 506,676,497	-1.02%	$ (94,699,654)
Transmission	2,223,817,638	2.20%	48,853,050	2.69%	59,918,194	2.50%	55,572,414	-0.20%	(4,345,780)
Distribution	4,670,120,248	2.22%	103,511,101	2.84%	132,474,796	2.34%	109,181,746	-0.50%	(23,293,050)
General	770,652,643	4.23%	32,573,358	5.06%	38,969,644	5.01%	38,579,317	-0.05%	(390,327)
Total Plant Studied	**$ 16,929,597,634**	**3.38%**	**$ 571,990,469**	**4.92%**	**$ 832,738,785**	**4.19%**	**$ 710,009,975**	**-0.72%**	**$ (122,728,810)**

Depreciation Parameter Comparison

Account No.	Description	Current Parameters Net Salvage	Current Parameters Iowa Curve Type	Current Parameters Iowa Curve AL	DEI Position Net Salvage	DEI Position Iowa Curve Type	DEI Position Iowa Curve AL	OUCC Position Net Salvage	OUCC Position Iowa Curve Type	OUCC Position Iowa Curve AL
	TRANSMISSION PLANT									
350.10	RIGHTS OF WAY	0%	R4	80	0%	R4	80	0%	R4	80
352.00	STRUCTURES AND IMPROVEMENTS	-5%	R2.5	70	-5%	R2.5	70	-5%	R2.5	70
353.00	STATION EQUIPMENT	-10%	R1.5	53	-15%	R1	54	-11%	R1	54
354.00	TOWERS AND FIXTURES	-30%	R3	75	-40%	R3	80	-33%	R3	88
355.00	POLES AND FIXTURES	-50%	R1	55	-30%	R1	45	-30%	R1	45
356.00	OVERHEAD CONDUCTORS AND DEVICES	-60%	R2.5	65	-70%	R2	65	-63%	R2	74
357.00	UNDERGROUND CONDUIT	0%	R3	65	0%	R2	40	0%	R2	40
358.00	UNDERGROUND CONDUCTOR AND DEVICES	0%	R4	40	-5%	R3	35	-1%	R3	35
	DISTRIBUTION PLANT									
360.10	RIGHTS OF WAY	0%	R4	75	0%	R4	75	0%	R4	75
361.00	STRUCTURES AND IMPROVEMENTS	-15%	R2	65	-10%	R2	55	-10%	R2	55
362.00	STATION EQUIPMENT	-15%	S0.5	52	-15%	S0	45	-15%	S0	45
363.01	BATTERY STORAGE	0%			0%	L3	15	0%	L3	15
364.00	POLES, TOWERS AND FIXTURES	-50%	R0.5	55	-80%	R0.5	57	-58%	R0.5	57
365.00	OVERHEAD CONDUCTORS AND DEVICES	-40%	R0.5	55	-60%	R0.5	45	-45%	O3	57
366.00	UNDERGROUND CONDUIT	-25%	R2	55	-25%	R2	60	-25%	R2	60
367.00	UNDERGROUND CONDUCTORS AND DEVICES	-25%	R2.5	55	-30%	R2	60	-26%	R1.5	68
368.00	LINE TRANSFORMERS	-20%	R0.5	44	-25%	R0.5	44	-21%	R0.5	44
369.00	SERVICES	-25%	R0.5	55	-30%	R1	60	-26%	R1	60
369.10	SERVICES - UNDERGROUND	-25%	R0.5	55	-30%	R1	60	-26%	R1	60
369.20	SERVICES - OVERHEAD	-25%	R0.5	55	-30%	R1	60	-26%	R1	60

Depreciation Parameter Comparison

Account No.	Description	Current Parameters Net Salvage	Current Parameters Iowa Curve Type	Current Parameters Iowa Curve AL	DEI Position Net Salvage	DEI Position Iowa Curve Type	DEI Position Iowa Curve AL	OUCC Position Net Salvage	OUCC Position Iowa Curve Type	OUCC Position Iowa Curve AL
370.00	METERS	-1%	S0.5	30	-2%	S0.5	25	-1%	S0.5	25
370.20	METERS - AMI	0%	S2.5	15	-2%	S2.5	15	-1%	S2.5	15
370.70	EV CHARGER/METER	0%			0%	S3	10	0%	S3	10
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	-10%	L0	20	-15%	L0	20	-11%	L0	20
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	-15%	O1	28	-15%	O1	30	-15%	O1	30
	GENERAL PLANT									
390.00	STRUCTURES AND IMPROVEMENTS	-10%	S0.5	55	-15%	R1.5	45	-11%	R1.5	45
391.00	OFFICE FURNITURE AND EQUIPMENT	0%	SQ	20	0%	SQ	20	0%	SQ	20
391.10	OFFICE FURNITURE AND EQUIPMENT - EDP	0%	SQ	5	0%	SQ	5	0%	SQ	5
392.00	TRANSPORTATION EQUIPMENT	5%	L3	22	10%	L2.5	20	10%	L2.5	20
393.00	STORES EQUIPMENT	0%	SQ	20	0%	SQ	20	0%	SQ	20
393.10	FORKLIFTS	0%	SQ	25	0%	SQ	25	0%	SQ	25
394.00	TOOLS,SHOPS AND GARAGE EQUIPMENT	0%	SQ	25	0%	SQ	25	0%	SQ	25
394.70	EV CHARGER	0%			0%	R3	15	0%	R3	15
395.00	LABORATORY EQUIPMENT	0%	SQ	20	0%	SQ	20	0%	SQ	20
396.00	POWER OPERATED EQUIPMENT	0%	R0.5	22	10%	R1	23	10%	R1	23
397.00	COMMUNICATION EQUIPMENT	0%	SQ	20	0%	SQ	20	0%	SQ	20
398.00	MISCELLANEOUS EQUIPMENT	0%	SQ	15	0%	SQ	15	0%	SQ	15

Detailed Rate Comparison

		[1]	[2]		[3]		[4]		[5]	
			Current Parameters		DEI Position		OUCC Position		OUCC Adjustment	
Account No.	Description	Plant 6/30/2023	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
	STEAM PRODUCTION PLANT									
311.00	Structures & Improvements									
	WABASHRIVER COMMON 2-6	73	0.00%	0	0.00%	0	0.00%	0	0.00%	0
	CAYUGA UNIT 1	3,660,507	8.97%	328,275	15.64%	572,442	13.02%	476,491	-2.62%	-95,951
	CAYUGA UNIT 2	1,306,401	8.35%	109,053	13.16%	171,872	10.95%	143,080	-2.21%	-28,792
	CAYUGA COMMON 1-2	130,963,099	7.05%	9,238,801	12.40%	16,241,011	10.17%	13,322,478	-2.23%	-2,918,533
	CAYUGA INLAND CONTAINER	756,820	3.23%	24,431	9.78%	73,996	7.51%	56,822	-2.27%	-17,174
	GIBSON UNIT 1	21,582,707	2.26%	487,860	4.74%	1,022,405	3.72%	801,852	-1.02%	-220,553
	GIBSON UNIT 2	26,001,504	2.21%	574,834	4.68%	1,215,891	3.65%	948,177	-1.03%	-267,714
	GIBSON UNIT 3	34,958,924	2.50%	872,981	5.79%	2,025,806	4.40%	1,537,966	-1.39%	-487,840
	GIBSON UNIT 4	27,554,894	2.56%	705,058	5.93%	1,635,130	4.55%	1,253,252	-1.38%	-381,878
	GIBSON UNIT 5	24,991,190	3.80%	948,980	9.21%	2,300,877	6.97%	1,742,820	-2.24%	-558,057
	GIBSON 3 FLUE GAS	391,692	3.10%	12,134	6.00%	23,498	4.60%	18,036	-1.40%	-5,462
	GIBSON 4 FLUE GAS	33,626,121	3.16%	1,062,494	6.06%	2,038,592	4.67%	1,571,745	-1.39%	-466,847
	GIBSON 5 FLUE GAS	2,537,916	3.66%	92,818	8.80%	223,346	6.56%	166,580	-2.24%	-56,766
	GIBSON COMMON 1-2	9,648,571	3.38%	325,940	5.56%	536,711	4.56%	439,974	-1.00%	-96,737
	GIBSON COMMON 1-3	81,727,067	3.92%	3,205,348	5.71%	4,665,009	4.70%	3,844,595	-1.01%	-820,414
	GIBSON COMMON 1-4	6,992,763	3.21%	224,729	7.45%	520,797	6.45%	450,817	-1.00%	-69,980
	GIBSON COMMON 1-5	222,709,671	4.57%	10,168,254	6.35%	14,141,455	5.33%	11,880,385	-1.02%	-2,261,070
	GIBSON COMMON 3-4	1,865,692	4.75%	88,603	7.34%	137,025	5.97%	111,442	-1.37%	-25,583
	GIBSON COMMON 4-5	10,505,774	3.26%	342,916	6.22%	653,333	4.83%	507,269	-1.39%	-146,064
	GIBSON COMMON 3-5	1,870,726	3.63%	67,995	6.73%	125,974	5.35%	100,018	-1.38%	-25,956
	Total 311.00	643,652,111	4.49%	28,881,504	7.51%	48,325,170	6.12%	39,373,801	-1.39%	-8,951,369
311.20	Structures & Improvements - Edwardsport IGCC									
	EDWARDSPORT IGCC	160,837,704	3.45%	5,550,311	4.01%	6,447,978	3.91%	6,286,915	-0.10%	-161,063
	Total 311.20	160,837,704	3.45%	5,550,311	4.01%	6,447,978	3.91%	6,286,915	-0.10%	-161,063
312.00	Boiler Plant Equipment									
	CAYUGA UNIT 1	504,617,020	6.53%	32,928,422	11.02%	55,626,019	8.33%	42,040,547	-2.69%	-13,585,472
	CAYUGA UNIT 2	458,072,527	6.30%	28,865,216	9.65%	44,213,161	7.33%	33,568,133	-2.32%	-10,645,028
	CAYUGA COMMON 1-2	189,314,863	9.06%	17,153,185	11.85%	22,441,979	9.66%	18,281,319	-2.19%	-4,160,660
	CAYUGA INLAND CONTAINER	2,437,060	2.78%	67,646	7.13%	173,715	4.67%	113,817	-2.46%	-59,898
	GIBSON UNIT 1	345,666,475	3.81%	13,154,836	5.39%	18,634,373	4.30%	14,874,095	-1.09%	-3,760,278
	GIBSON UNIT 2	338,180,652	3.73%	12,607,918	5.32%	17,990,887	4.21%	14,231,420	-1.11%	-3,759,467
	GIBSON UNIT 3	344,645,832	4.40%	15,160,377	6.29%	21,665,645	4.81%	16,575,846	-1.48%	-5,089,799
	GIBSON UNIT 4	356,121,395	4.36%	15,513,773	6.54%	23,276,532	5.10%	18,148,090	-1.44%	-5,128,442
	GIBSON UNIT 5	173,942,835	6.45%	11,213,636	8.75%	15,215,371	6.50%	11,299,021	-2.25%	-3,916,350
	GIBSON 1 FLUE GAS	140,265,808	3.87%	5,423,813	4.94%	6,931,318	3.82%	5,361,591	-1.12%	-1,569,727
	GIBSON 2 FLUE GAS	146,447,392	3.86%	5,649,110	4.94%	7,228,826	3.82%	5,587,882	-1.12%	-1,640,944
	GIBSON 3 FLUE GAS	209,164,024	4.21%	8,796,776	5.60%	11,722,979	4.13%	8,641,442	-1.47%	-3,081,537
	GIBSON 4 FLUE GAS	137,645,340	3.35%	4,611,174	5.37%	7,393,405	3.87%	5,323,933	-1.50%	-2,069,472
	GIBSON 5 FLUE GAS	59,525,035	5.37%	3,196,283	8.31%	4,947,366	5.98%	3,561,008	-2.33%	-1,386,358
	GIBSON COMMON 1-2	7,027,590	3.08%	216,573	5.71%	401,371	4.58%	321,628	-1.13%	-79,743

Detailed Rate Comparison

		[1]	[2]		[3]		[4]		[5]	
			Current Parameters		DEI Position		OUCC Position		OUCC Adjustment	
Account No.	Description	Plant 6/30/2023	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
	GIBSON COMMON 1-3	248,486,696	4.93%	12,258,330	5.91%	14,674,272	4.85%	12,063,612	-1.06%	-2,610,660
	GIBSON COMMON 1-4	8,633,960	4.17%	360,032	7.32%	631,932	6.29%	543,069	-1.03%	-88,863
	GIBSON COMMON 1-5	121,306,607	3.42%	4,151,626	6.02%	7,301,185	4.91%	5,959,473	-1.11%	-1,341,712
	GIBSON COMMON 3-4	11,084,456	2.84%	315,263	5.21%	577,308	3.59%	398,473	-1.62%	-178,835
	GIBSON COMMON 4-5	9,654,561	2.99%	288,825	5.16%	497,982	3.58%	345,557	-1.58%	-152,425
	GIBSON COMMON 3-5	1,685,960	6.27%	105,657	9.07%	152,927	7.66%	129,208	-1.41%	-23,719
	Total 312.00	3,813,926,090	5.04%	192,038,471	7.39%	281,698,553	5.70%	217,369,164	-1.69%	-64,329,389
312.10	Boiler Plant Equipment - Coal Cars									
	GIBSON COMMON 1-5	2,914,385	2.43%	70,787	0.24%	7,105	3.24%	94,562	3.00%	87,457
	Total 312.10	2,914,385	2.43%	70,787	0.24%	7,105	3.24%	94,562	3.00%	87,457
312.20	Boiler Plant Equipment - Edwardsport IGCC									
	EDWARDSPORT IGCC	1,846,072,348	3.71%	68,522,684	5.21%	96,208,301	5.06%	93,358,947	-0.15%	-2,849,354
	Total 312.20	1,846,072,348	3.71%	68,522,684	5.21%	96,208,301	5.06%	93,358,947	-0.15%	-2,849,354
312.30	Boiler Plant Equipment - SCR Catalyst									
	GIBSON UNIT 1	3,241,112	7.24%	234,749	11.53%	373,781	8.49%	275,168	-3.04%	-98,613
	GIBSON UNIT 2	6,189,864	7.24%	448,166	15.28%	946,002	10.03%	621,040	-5.25%	-324,962
	GIBSON UNIT 3	5,652,917	7.24%	409,331	16.03%	906,342	10.33%	583,698	-5.70%	-322,644
	GIBSON UNIT 4	2,389,346	7.33%	175,077	10.03%	239,537	7.56%	180,747	-2.47%	-58,790
	GIBSON UNIT 5	2,528,243	7.51%	189,963	13.20%	333,639	9.54%	241,230	-3.66%	-92,409
	Total 312.30	20,001,482	7.29%	1,457,286	14.00%	2,799,301	9.51%	1,901,883	-4.49%	-897,418
314.00	Turbogenerator Units									
	CAYUGA UNIT 1	48,635,231	5.62%	2,731,948	12.81%	6,232,161	10.18%	4,952,366	-2.63%	-1,279,795
	CAYUGA UNIT 2	49,013,609	5.22%	2,560,528	10.67%	5,230,453	8.41%	4,119,774	-2.26%	-1,110,679
	CAYUGA COMMON 1-2	18,608,100	4.93%	917,751	9.22%	1,715,628	6.96%	1,294,260	-2.26%	-421,368
	GIBSON UNIT 1	59,983,200	3.96%	2,374,091	5.39%	3,234,534	4.31%	2,586,076	-1.08%	-648,458
	GIBSON UNIT 2	58,505,120	3.88%	2,271,451	5.24%	3,067,984	4.17%	2,439,167	-1.07%	-628,817
	GIBSON UNIT 3	60,214,945	4.40%	2,650,248	6.17%	3,716,198	4.73%	2,850,606	-1.44%	-865,592
	GIBSON UNIT 4	65,438,100	4.48%	2,931,617	6.58%	4,308,707	5.16%	3,373,637	-1.42%	-935,070
	GIBSON UNIT 5	37,070,734	6.70%	2,481,962	9.00%	3,336,735	6.75%	2,500,724	-2.25%	-836,011
	GIBSON COMMON 1-2	3,242,254	2.95%	95,630	5.13%	166,386	4.01%	130,072	-1.12%	-36,314
	GIBSON COMMON 1-4	1,520,129	3.21%	48,822	7.35%	111,672	6.31%	95,928	-1.04%	-15,744
	GIBSON COMMON 1-5	6,579,530	3.21%	211,315	6.85%	450,803	5.83%	383,277	-1.02%	-67,526
	GIBSON COMMON 3-4	434,495	2.93%	12,714	8.25%	35,830	6.86%	29,806	-1.39%	-6,024
	GIBSON COMMON 3-5	2,736,096	3.33%	91,110	6.08%	166,336	4.63%	126,723	-1.45%	-39,613
	Total 314.00	411,981,542	4.70%	19,379,187	7.71%	31,773,427	6.04%	24,882,417	-1.67%	-6,891,010
314.20	Turbogenerator Units - Edwardsport IGCC									
	EDWARDSPORT IGCC	589,452,381	3.63%	21,390,311	10.54%	62,111,935	10.27%	60,511,680	-0.27%	-1,600,255

Detailed Rate Comparison

Account No.	Description	[1] Plant 6/30/2023	[2] Current Parameters Rate	[2] Current Parameters Annual Accrual	[3] DEI Position Rate	[3] DEI Position Annual Accrual	[4] OUCC Position Rate	[4] OUCC Position Annual Accrual	[5] OUCC Adjustment Rate	[5] OUCC Adjustment Annual Accrual
	Total 314.20	589,452,381	3.63%	21,390,311	10.54%	62,111,935	10.27%	60,511,680	-0.27%	-1,600,255
314.30	PRIME MOVERS - EDWARDSPORT IGCC									
	EDWARDSPORT IGCC	90,429,354	0.00%	0	3.90%	3,527,195	3.80%	3,438,969	-0.10%	-88,226
	Total 314.30	90,429,354	0.00%	0	3.90%	3,527,195	3.80%	3,438,969	-0.10%	-88,226
315.00	Accessory Electrical Equipment									
	CAYUGA UNIT 1	10,460,175	5.01%	524,109	13.24%	1,385,183	10.67%	1,115,997	-2.57%	-269,186
	CAYUGA UNIT 2	8,684,941	6.13%	532,156	11.72%	1,018,171	9.54%	828,948	-2.18%	-189,223
	CAYUGA COMMON 1-2	3,993,949	4.06%	162,230	12.20%	487,361	10.04%	401,054	-2.16%	-86,307
	CAYUGA INLAND CONTAINER	232,950	2.36%	5,496	7.22%	16,829	4.97%	11,588	-2.25%	-5,241
	GIBSON UNIT 1	16,672,670	4.39%	732,592	5.05%	842,740	4.01%	668,339	-1.04%	-174,401
	GIBSON UNIT 2	21,650,224	3.26%	705,425	4.88%	1,056,501	3.82%	827,370	-1.06%	-229,131
	GIBSON UNIT 3	16,283,732	2.90%	472,596	5.21%	849,176	3.80%	618,139	-1.41%	-231,037
	GIBSON UNIT 4	12,666,711	3.52%	446,190	5.77%	731,162	4.36%	552,600	-1.41%	-178,562
	GIBSON UNIT 5	15,781,369	5.04%	795,280	8.12%	1,281,954	5.87%	926,390	-2.25%	-355,564
	GIBSON 4 FLUE GAS	8,299,265	2.93%	243,487	4.93%	409,148	3.52%	292,148	-1.41%	-117,000
	GIBSON 5 FLUE GAS	2,138,719	2.92%	62,551	6.85%	146,605	4.62%	98,910	-2.23%	-47,695
	GIBSON COMMON 1-2	719,765	2.27%	16,317	7.41%	53,369	6.37%	45,816	-1.04%	-7,553
	GIBSON COMMON 1-3	1,159,798	2.68%	31,074	4.01%	46,468	2.94%	34,080	-1.07%	-12,388
	GIBSON COMMON 1-4	78,568	2.55%	2,000	3.93%	3,084	2.86%	2,250	-1.07%	-834
	GIBSON COMMON 1-5	15,536,546	2.67%	415,196	5.94%	922,938	4.90%	761,668	-1.04%	-161,270
	GIBSON COMMON 3-4	309,196	5.16%	15,946	7.81%	24,137	6.41%	19,814	-1.40%	-4,323
	GIBSON COMMON 3-5	247,472	2.65%	6,558	9.76%	24,160	8.40%	20,781	-1.36%	-3,379
	GIBSON COMMON 4-5	331,977	2.65%	8,797	4.46%	14,804	3.00%	9,959	-1.46%	-4,845
	Total 315.00	135,248,027	3.83%	5,178,000	6.89%	9,313,790	5.35%	7,235,852	-1.54%	-2,077,938
315.20	Accessory Electric Equipment - Edwardsport IGCC									
	EDWARDSPORT IGCC	44,354,359	3.79%	1,682,275	4.40%	1,951,646	4.28%	1,900,428	-0.12%	-51,218
	Total 315.20	44,354,359	3.79%	1,682,275	4.40%	1,951,646	4.28%	1,900,428	-0.12%	-51,218
316.00	Miscellaneous Power Plant Equip.									
	NOBLESVILLE	29,251	9.58%	2,802	9.58%	2,803	8.40%	2,457	-1.18%	-346
	CAYUGA UNIT 1	8,852,202	6.28%	555,612	10.94%	968,542	8.25%	730,357	-2.69%	-238,185
	CAYUGA UNIT 2	7,042,084	4.90%	344,956	8.57%	603,775	6.35%	446,942	-2.22%	-156,833
	CAYUGA COMMON 1-2	19,695,159	7.41%	1,458,454	12.04%	2,371,212	9.79%	1,928,037	-2.25%	-443,175
	CAYUGA INLAND CONTAINER	144,121	4.59%	6,612	8.13%	11,710	5.89%	8,485	-2.24%	-3,225
	GIBSON UNIT 1	7,098,118	4.06%	287,929	5.12%	363,334	4.04%	286,825	-1.08%	-76,509
	GIBSON UNIT 2	4,804,584	3.70%	177,678	4.72%	226,869	3.64%	174,871	-1.08%	-51,998
	GIBSON UNIT 3	7,511,336	4.15%	311,349	5.46%	410,438	4.03%	302,651	-1.43%	-107,787
	GIBSON UNIT 4	7,789,994	4.14%	322,585	5.52%	430,219	4.08%	318,133	-1.44%	-112,086
	GIBSON UNIT 5	3,950,101	6.28%	248,138	8.33%	328,965	6.08%	240,197	-2.25%	-88,768
	GIBSON 4 FLUE GAS	1,156,459	4.84%	56,003	6.05%	69,973	4.60%	53,230	-1.45%	-16,743

Detailed Rate Comparison

Account No.	Description	[1] Plant 6/30/2023	[2] Current Parameters Rate	[2] Current Parameters Annual Accrual	[3] DEI Position Rate	[3] DEI Position Annual Accrual	[4] OUCC Position Rate	[4] OUCC Position Annual Accrual	[5] OUCC Adjustment Rate	[5] OUCC Adjustment Annual Accrual
	GIBSON 5 FLUE GAS	1,658,109	6.34%	105,138	8.22%	136,373	5.98%	99,236	-2.24%	-37,137
	GIBSON COMMON 1-2	1,622,535	3.29%	53,365	4.35%	70,553	3.25%	52,714	-1.10%	-17,839
	GIBSON COMMON 1-3	217,962	3.77%	8,208	4.77%	10,397	3.68%	8,030	-1.09%	-2,367
	GIBSON COMMON 1-4	10,945,997	5.50%	601,758	6.52%	713,352	5.47%	599,173	-1.05%	-114,179
	GIBSON COMMON 1-5	33,496,416	3.93%	1,315,144	5.28%	1,768,826	4.20%	1,406,627	-1.08%	-362,199
	GIBSON COMMON 3-4	114,216	3.18%	3,632	4.74%	5,413	3.22%	3,679	-1.52%	-1,734
	GIBSON COMMON 3-5	34,328	3.18%	1,092	9.87%	3,389	8.46%	2,904	-1.41%	-485
	GIBSON COMMON 4-5	12,729	3.80%	484	5.16%	657	3.70%	471	-1.46%	-186
	Total 316.00	116,175,700	5.04%	5,860,939	7.31%	8,496,800	5.74%	6,665,019	-1.58%	-1,831,781
316.20	Misc. Power Plant Equipment - Edwardsport IGCC									
	EDWARDSPORT IGCC	18,853,854	4.07%	766,448	4.76%	896,981	4.66%	879,102	-0.10%	-17,879
	Total 316.20	18,853,854	4.07%	766,448	4.76%	896,981	4.66%	879,102	-0.09%	-17,879
	Total Steam Production Plant	7,893,899,337	4.44%	350,778,203	7.01%	553,558,182	5.88%	463,898,740	-1.14%	-89,659,442
	HYDRAULIC PRODUCTION PLANT									
331.00	Structures & Improvements	4,649,452	0.42%	19,606	0.52%	24,287	0.42%	19,329	-0.10%	-4,958
332.00	Reservoirs, Dams & Waterways	16,001,334	0.70%	111,779	0.57%	91,079	0.46%	73,846	-0.11%	-17,233
333.00	Waterwheels, Turbines & Generators	126,005,807	2.75%	3,467,161	3.11%	3,919,329	3.00%	3,774,330	-0.11%	-144,999
334.00	Accessory Electrical Equip.	8,480,936	4.33%	367,568	3.26%	276,387	3.14%	266,610	-0.12%	-9,777
335.00	Misc. Power Plant Equip.	1,794,412	3.01%	54,004	2.16%	38,698	2.02%	36,325	-0.14%	-2,373
	Total Hydraulic Production Plant	156,931,940	2.56%	4,020,118	2.77%	4,349,780	2.66%	4,170,439	-0.11%	-179,341
	OTHER PRODUCTION PLANT									
341.00	Structures & Improvements									
	NOBLESVILLE	16,410,639	3.44%	564,016	4.47%	732,825	3.16%	518,743	-1.31%	-214,082
	NOBLESVILLE CT UNIT 3	3,163,542	3.28%	103,651	3.88%	122,703	2.66%	84,304	-1.22%	-38,399
	NOBLESVILLE CT UNIT 4	3,163,275	3.28%	103,635	3.88%	122,686	2.66%	84,290	-1.22%	-38,396
	NOBLESVILLE CT UNIT 5	3,182,777	3.28%	104,352	3.88%	123,515	2.67%	84,889	-1.21%	-38,626
	VERMILLION CT STATION	4,966,083	2.56%	126,991	2.75%	136,352	2.64%	131,197	-0.11%	-5,155
	CAYUGA CT UNIT 4	5,776,462	2.75%	159,041	2.86%	165,346	2.69%	155,514	-0.17%	-9,832
	CINCAP MADISON CT 1-8	10,493,056	2.61%	273,735	3.01%	315,676	2.95%	309,426	-0.06%	-6,250
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	6,096,749	3.10%	188,712	3.69%	225,213	3.49%	212,843	-0.20%	-12,370
	CAYUGA DIESEL	5,515	1.41%	78	2.52%	139	2.11%	116	-0.41%	-23
	WHEATLAND CT UNIT 1	28,000	2.81%	788	2.98%	834	2.92%	818	-0.06%	-16
	WHEATLAND CT UNIT 2	28,000	2.81%	788	2.98%	834	2.92%	818	-0.06%	-16
	WHEATLAND CT UNIT 3	251,291	2.81%	7,069	4.80%	12,051	4.75%	11,944	-0.05%	-107
	WHEATLAND CT UNIT 4	28,000	2.81%	788	2.98%	834	2.92%	818	-0.06%	-16
	WHEATLAND COMMON CT 1-4	1,183,850	3.86%	45,742	3.97%	46,946	3.92%	46,386	-0.05%	-560

Detailed Rate Comparison

		[1]	[2]		[3]		[4]		[5]	
			Current Parameters		DEI Position		OUCC Position		OUCC Adjustment	
Account No.	Description	Plant 6/30/2023	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
	PURDUE CHP	14,589,461	0.00%	0	3.19%	465,426	3.13%	456,537	-0.06%	-8,889
	Total 341.00	69,366,700	2.42%	1,679,386	3.56%	2,471,380	3.03%	2,098,642	-0.54%	-372,738
341.66	STRUCTURES AND IMPROVEMENTS - SOLAR									
	CRANE SOLAR	401,873	4.40%	17,682	3.06%	12,287	2.89%	11,598	-0.17%	-689
	Total 341.66	401,873	4.40%	17,682	3.06%	12,287	2.89%	11,598	-0.17%	-689
342.00	Fuel Holders, Producers and Accessories									
	NOBLESVILLE	659,972	5.32%	35,134	6.52%	43,045	5.35%	35,307	-1.17%	-7,738
	NOBLESVILLE CT UNIT 3	44,569	4.59%	2,046	2.74%	1,219	1.55%	692	-1.19%	-527
	NOBLESVILLE CT UNIT 4	306,714	5.63%	17,258	6.67%	20,450	5.49%	16,851	-1.18%	-3,599
	NOBLESVILLE CT UNIT 5	152,543	6.08%	9,279	5.36%	8,183	4.19%	6,387	-1.17%	-1,796
	NOBLESVILLE COMMON 3-5	6,749,463	2.56%	173,008	2.27%	153,073	1.08%	72,605	-1.19%	-80,468
	VERMILLION CT STATION	21,309,587	2.20%	469,683	1.94%	414,284	1.84%	391,835	-0.10%	-22,449
	CAYUGA CT UNIT 4	2,868,642	1.00%	28,579	1.56%	44,830	1.40%	40,217	-0.16%	-4,613
	CINCAP MADISON CT 1-8	9,285,364	2.10%	194,767	1.84%	171,020	1.79%	166,086	-0.05%	-4,934
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	785,745	3.18%	24,998	4.03%	31,678	3.84%	30,154	-0.19%	-1,524
	CAYUGA DIESEL	25,530	0.00%	0	0.00%	0	0.00%	0	0.00%	0
	WHEATLAND CT UNIT 1	110,000	2.47%	2,715	2.23%	2,453	2.18%	2,399	-0.05%	-54
	WHEATLAND CT UNIT 2	145,404	3.46%	5,030	3.21%	4,663	3.15%	4,582	-0.06%	-81
	WHEATLAND CT UNIT 3	110,000	2.47%	2,715	2.23%	2,453	2.18%	2,399	-0.05%	-54
	WHEATLAND CT UNIT 4	110,000	2.47%	2,715	2.23%	2,453	2.18%	2,399	-0.05%	-54
	WHEATLAND COMMON CT 1-4	825,592	2.47%	20,379	2.57%	21,213	2.52%	20,836	-0.05%	-377
	PURDUE CHP	832,096	0.00%	0	1.15%	9,588	1.09%	9,096	-0.06%	-492
	Total 342.00	44,321,221	2.23%	988,306	2.10%	930,605	1.81%	801,847	-0.29%	-128,758
343.00	Prime Movers									
	NOBLESVILLE	41,775,759	4.18%	1,747,313	6.16%	2,571,977	4.88%	2,036,808	-1.28%	-535,169
	NOBLESVILLE CT UNIT 3	39,803,772	3.86%	1,535,953	5.48%	2,180,594	4.19%	1,667,091	-1.29%	-513,503
	NOBLESVILLE CT UNIT 4	37,186,697	4.18%	1,554,483	5.40%	2,009,112	4.11%	1,526,649	-1.29%	-482,463
	NOBLESVILLE CT UNIT 5	38,689,635	4.01%	1,552,146	5.63%	2,178,106	4.34%	1,679,241	-1.29%	-498,865
	VERMILLION CT STATION	11,982,114	3.42%	409,436	4.83%	578,476	4.72%	565,496	-0.11%	-12,980
	CAYUGA CT UNIT 4	31,337,960	3.03%	949,747	4.50%	1,409,870	4.33%	1,358,357	-0.17%	-51,513
	CINCAP MADISON CT UNIT 5	452,491	4.89%	22,107	5.85%	26,460	5.79%	26,196	-0.06%	-264
	CINCAP MADISON CT 1-8	205,898,963	3.14%	6,470,401	3.83%	7,884,898	3.75%	7,726,300	-0.08%	-158,598
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	48,047,008	3.86%	1,852,410	4.80%	2,307,267	4.58%	2,200,437	-0.22%	-106,830
	WHEATLAND CT UNIT 1	24,479,523	3.74%	916,738	4.18%	1,022,761	4.11%	1,007,125	-0.07%	-15,636
	WHEATLAND CT UNIT 2	16,265,414	3.30%	536,091	4.01%	651,812	3.94%	641,661	-0.07%	-10,151
	WHEATLAND CT UNIT 3	13,916,184	3.34%	464,545	3.98%	554,297	3.93%	546,559	-0.05%	-7,738
	WHEATLAND CT UNIT 4	16,871,646	3.24%	547,368	3.85%	650,351	3.80%	640,745	-0.05%	-9,606
	WHEATLAND COMMON CT 1-4	1,339,096	3.93%	52,640	4.53%	60,711	4.47%	59,908	-0.06%	-803
	PURDUE CHP	16,000,278	0.00%	0	3.52%	562,742	3.44%	550,766	-0.08%	-11,976
	Total 343.00	544,046,540	3.42%	18,611,378	4.53%	24,649,434	4.09%	22,233,339	-0.44%	-2,416,095

Detailed Rate Comparison

		[1]	[2]		[3]		[4]		[5]	
			Current Parameters		DEI Position		OUCC Position		OUCC Adjustment	
Account No.	Description	Plant 6/30/2023	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
343.10	PRIME MOVERS - ROTABLE PARTS									
	NOBLESVILLE	1,245,752	0.00%	0	0.00%	0	0.00%	0	0.00%	0
	NOBLESVILLE CT UNIT 3	15,741,851	0.00%	0	2.23%	351,386	0.76%	119,401	-1.47%	-231,985
	NOBLESVILLE CT UNIT 4	15,399,004	0.00%	0	4.15%	639,539	2.75%	424,188	-1.40%	-215,351
	NOBLESVILLE CT UNIT 5	14,298,975	0.00%	0	3.50%	499,893	1.98%	282,950	-1.52%	-216,943
	VERMILLION CT STATION	9,622,671	0.00%	0	1.29%	124,233	1.11%	106,426	-0.18%	-17,807
	CINCAP MADISON CT UNIT 5	1,573,076	0.00%	0	7.04%	110,821	6.96%	109,510	-0.08%	-1,311
	CINCAP MADISON CT 1-8	32,132,531	0.00%	0	0.05%	16,334	-0.03%	-10,443	-0.08%	-26,777
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	9,550,566	0.00%	0	0.00%	476	-0.25%	-24,013	-0.25%	-24,489
	WHEATLAND CT UNIT 2	8,705,071	0.00%	0	6.90%	600,886	6.83%	594,633	-0.07%	-6,253
	WHEATLAND CT UNIT 3	10,897,303	0.00%	0	1.77%	192,608	1.65%	180,344	-0.12%	-12,264
	WHEATLAND CT UNIT 4	1,862,583	0.00%	0	1.77%	32,921	1.65%	30,825	-0.12%	-2,096
	PURDUE CHP	1,908,792	0.00%	0	7.22%	137,811	7.01%	133,751	-0.21%	-4,060
	Total 343.10	122,938,174	0.00%	0	2.20%	2,706,908	1.58%	1,947,571	-0.62%	-759,337
344.00	GENERATORS									
	NOBLESVILLE	32,216,844	2.26%	728,987	2.43%	784,293	1.23%	395,271	-1.20%	-389,022
	NOBLESVILLE CT UNIT 3	4,810,989	2.26%	108,918	6.43%	309,108	5.22%	251,357	-1.21%	-57,751
	NOBLESVILLE CT UNIT 4	3,720,635	2.32%	86,136	5.51%	204,891	4.33%	161,199	-1.18%	-43,692
	NOBLESVILLE CT UNIT 5	2,869,494	2.30%	65,997	6.35%	182,313	5.16%	148,207	-1.19%	-34,106
	VERMILLION CT STATION	117,105,325	1.89%	2,217,349	1.86%	2,174,249	1.74%	2,041,703	-0.12%	-132,546
	CAYUGA CT UNIT 4	9,937,169	1.07%	106,246	1.60%	159,402	1.44%	143,357	-0.16%	-16,045
	CINCAP MADISON CT 1-8	70,254,584	1.89%	1,326,953	1.81%	1,271,768	1.74%	1,225,413	-0.07%	-46,355
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	25,229,111	1.99%	501,932	1.91%	482,545	1.70%	429,183	-0.21%	-53,362
	CAYUGA DIESEL	1,950,116	2.25%	43,838	1.08%	21,030	0.74%	14,451	-0.34%	-6,579
	WHEATLAND CT UNIT 1	5,886,136	2.33%	137,170	3.45%	202,992	3.40%	200,235	-0.05%	-2,757
	WHEATLAND CT UNIT 2	4,059,676	2.33%	94,606	2.21%	89,753	2.15%	87,387	-0.06%	-2,366
	WHEATLAND CT UNIT 3	4,059,676	2.33%	94,606	2.21%	89,753	2.15%	87,387	-0.06%	-2,366
	WHEATLAND CT UNIT 4	4,389,971	2.33%	102,303	2.50%	109,848	2.45%	107,471	-0.05%	-2,377
	WHEATLAND COMMON CT 1-4	555,876	3.66%	20,367	4.41%	24,525	4.37%	24,274	-0.04%	-251
	PURDUE CHP	12,454,709	0.00%	0	2.82%	350,919	2.76%	343,619	-0.06%	-7,300
	Total 344.00	299,500,312	1.88%	5,635,408	2.16%	6,457,389	1.89%	5,660,513	-0.27%	-796,876
344.66	GENERATORS - SOLAR									
	CRANE SOLAR	32,498,249	3.92%	1,275,537	4.24%	1,377,538	4.03%	1,309,797	-0.21%	-67,741
	CAMP ATTERBURY MICROGRID	5,395,191	4.52%	243,863	4.34%	234,344	4.31%	232,471	-0.03%	-1,873
	Total 344.66	37,893,440	4.01%	1,519,400	4.25%	1,611,882	4.07%	1,542,269	-0.18%	-69,613
345.00	Accessory Electric Equipment									
	NOBLESVILLE	5,263,616	5.34%	281,164	4.45%	234,283	3.23%	169,758	-1.22%	-64,525
	NOBLESVILLE CT UNIT 3	821,222	4.12%	33,841	3.79%	31,086	2.48%	20,332	-1.31%	-10,754
	NOBLESVILLE CT UNIT 4	921,731	4.56%	42,043	4.12%	38,018	2.84%	26,211	-1.28%	-11,807
	NOBLESVILLE CT UNIT 5	813,419	4.23%	34,395	3.74%	30,416	2.42%	19,712	-1.32%	-10,704

Detailed Rate Comparison

		[1]	[2]		[3]		[4]		[5]	
			Current Parameters		DEI Position		OUCC Position		OUCC Adjustment	
Account No.	Description	Plant 6/30/2023	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
	VERMILLION CT STATION	576,013	4.19%	24,154	3.23%	18,625	3.13%	18,029	-0.10%	-596
	CAYUGA CT UNIT 4	5,276,891	4.01%	211,865	3.28%	173,290	3.11%	163,915	-0.17%	-9,375
	CINCAP MADISON CT UNIT 2	50,087	4.27%	2,139	3.95%	1,977	3.88%	1,942	-0.07%	-35
	CINCAP MADISON CT UNIT 6	46,569	4.27%	1,989	3.95%	1,838	3.88%	1,806	-0.07%	-32
	CINCAP MADISON CT UNIT 7	48,262	4.27%	2,061	3.95%	1,905	3.88%	1,871	-0.07%	-34
	CINCAP MADISON CT UNIT 8	48,378	4.27%	2,066	3.95%	1,909	3.88%	1,876	-0.07%	-33
	CINCAP MADISON CT 1-8	13,378,339	3.67%	490,516	3.14%	420,134	3.08%	412,038	-0.06%	-8,096
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	4,974,916	4.62%	229,924	3.60%	179,123	3.38%	168,183	-0.22%	-10,940
	CAYUGA DIESEL	872,195	8.35%	72,838	5.65%	49,317	5.32%	46,392	-0.33%	-2,925
	WHEATLAND CT UNIT 1	556,463	3.63%	20,200	3.29%	18,289	3.23%	17,988	-0.06%	-301
	WHEATLAND CT UNIT 2	594,851	3.69%	21,943	3.33%	19,837	3.28%	19,506	-0.05%	-331
	WHEATLAND CT UNIT 3	525,418	3.63%	19,048	3.24%	17,043	3.18%	16,682	-0.06%	-361
	WHEATLAND CT UNIT 4	246,761	3.70%	9,133	3.48%	8,589	3.43%	8,468	-0.05%	-121
	WHEATLAND COMMON CT 1-4	2,019,408	4.17%	84,130	4.24%	85,712	4.20%	84,731	-0.04%	-981
	PURDUE CHP	8,899,540	0.00%	0	3.57%	318,151	3.50%	311,484	-0.07%	-6,667
	Total 345.00	45,934,080	3.45%	1,583,449	3.59%	1,649,542	3.29%	1,510,924	-0.30%	-138,618
345.66	ACCESSORY ELECTRIC EQUIPMENT - SOLAR									
	CRANE SOLAR	5,246,980	4.70%	246,453	4.64%	243,343	4.44%	233,057	-0.20%	-10,286
	Total 345.66	5,246,980	4.70%	246,453	4.64%	243,343	4.44%	233,057	-0.20%	-10,286
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	NOBLESVILLE	6,022,969	5.49%	330,432	6.87%	413,543	5.56%	335,065	-1.31%	-78,478
	NOBLESVILLE CT UNIT 3	2,173,761	5.02%	109,111	6.15%	133,649	4.85%	105,443	-1.30%	-28,206
	NOBLESVILLE CT UNIT 4	2,078,917	4.96%	103,162	6.04%	125,576	4.76%	98,902	-1.28%	-26,674
	NOBLESVILLE CT UNIT 5	2,105,949	4.99%	105,131	6.09%	128,319	4.78%	100,641	-1.31%	-27,678
	CAYUGA CT UNIT 4	1,246,913	7.00%	87,234	5.08%	63,291	4.90%	61,053	-0.18%	-2,238
	CINCAP MADISON CT 1-8	2,541,817	4.56%	115,798	5.08%	129,229	5.02%	127,718	-0.06%	-1,511
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	1,618,558	5.15%	83,293	6.05%	97,875	5.85%	94,674	-0.20%	-3,201
	CAYUGA DIESEL	311	6.06%	19	7.07%	22	6.59%	21	-0.48%	-1
	WHEATLAND CT UNIT 1	573,108	3.84%	21,994	4.17%	23,897	4.10%	23,488	-0.07%	-409
	WHEATLAND CT UNIT 2	573,663	3.81%	21,833	4.17%	23,926	4.10%	23,521	-0.07%	-405
	WHEATLAND CT UNIT 3	579,994	3.80%	22,041	4.17%	24,193	4.10%	23,785	-0.07%	-408
	WHEATLAND CT UNIT 4	575,640	3.81%	21,931	4.17%	24,030	4.11%	23,640	-0.06%	-390
	WHEATLAND COMMON CT 1-4	3,608,879	3.94%	142,370	4.34%	156,564	4.29%	154,809	-0.05%	-1,755
	PURDUE CHP	323,349	0.00%	0	3.54%	11,445	3.46%	11,203	-0.08%	-242
	Total 346.00	24,023,827	4.85%	1,164,349	5.64%	1,355,559	4.93%	1,183,965	-0.71%	-171,594
348.01	BATTERY STORAGE	20,502,681	3.94%	808,828	6.73%	1,379,860	6.75%	1,383,593	0.02%	3,733
	Total Other Production Plant	1,214,175,828	2.66%	32,254,639	3.58%	43,468,189	3.18%	38,607,318	-0.40%	-4,860,871
	Total Production Plant	**9,265,007,105**	**4.18%**	**387,052,960**	**6.49%**	**601,376,151**	**5.47%**	**506,676,497**	**-1.02%**	**-94,699,654**

Detailed Rate Comparison

Account No.	Description	[1] Plant 6/30/2023	[2] Current Parameters Rate	[2] Current Parameters Annual Accrual	[3] DEI Position Rate	[3] DEI Position Annual Accrual	[4] OUCC Position Rate	[4] OUCC Position Annual Accrual	[5] OUCC Adjustment Rate	[5] OUCC Adjustment Annual Accrual
	TRANSMISSION PLANT									
350.10	RIGHTS OF WAY	40,427,081	0.99%	398,896	0.97%	392,226	0.97%	391,924	0.00%	-302
352.00	STRUCTURES AND IMPROVEMENTS	82,753,143	1.50%	1,242,259	1.53%	1,263,332	1.53%	1,262,471	0.00%	-861
353.00	STATION EQUIPMENT	909,453,535	1.96%	17,867,994	2.13%	19,392,313	2.04%	18,528,857	-0.09%	-863,456
354.00	TOWERS AND FIXTURES	89,256,597	1.51%	1,344,537	1.60%	1,431,588	1.27%	1,130,574	-0.33%	-301,014
355.00	POLES AND FIXTURES	530,518,385	2.55%	13,552,805	4.08%	21,621,991	4.08%	21,626,337	0.00%	4,346
356.00	OVERHEAD CONDUCTORS AND DEVICES	568,924,400	2.53%	14,400,249	2.77%	15,735,030	2.21%	12,553,709	-0.56%	-3,181,321
357.00	UNDERGROUND CONDUIT	227,876	0.81%	1,835	1.53%	3,491	1.53%	3,488	0.00%	-3
358.00	UNDERGROUND CONDUCTOR AND DEVICES	2,256,621	1.97%	44,475	3.47%	78,223	3.33%	75,054	-0.14%	-3,169
	Total Transmission Plant	**2,223,817,638**	**2.20%**	**48,853,050**	**2.69%**	**59,918,194**	**2.50%**	**55,572,414**	**-0.20%**	**-4,345,780**
	DISTRIBUTION PLANT									
360.10	RIGHTS OF WAY	5,120,349	0.87%	44,657	1.23%	63,025	1.23%	63,028	0.00%	3
361.00	STRUCTURES AND IMPROVEMENTS	53,708,979	1.70%	914,172	2.07%	1,111,492	2.07%	1,111,015	0.00%	-477
362.00	STATION EQUIPMENT	796,636,440	1.83%	14,597,502	2.53%	20,153,148	2.53%	20,128,955	0.00%	-24,193
363.01	BATTERY STORAGE	3,265,111	6.71%	219,089	6.89%	225,100	6.89%	225,100	0.00%	0
364.00	POLES, TOWERS AND FIXTURES	669,356,236	2.05%	13,719,891	2.97%	19,895,230	2.52%	16,840,320	-0.45%	-3,054,910
365.00	OVERHEAD CONDUCTORS AND DEVICES	953,714,828	2.50%	23,866,280	4.04%	38,570,018	2.37%	22,649,157	-1.67%	-15,920,861
366.00	UNDERGROUND CONDUIT	76,947,858	2.66%	2,046,374	2.21%	1,699,421	2.21%	1,700,092	0.00%	671
367.00	UNDERGROUND CONDUCTORS AND DEVICES	866,289,998	2.17%	18,836,027	2.06%	17,816,100	1.70%	14,731,294	-0.36%	-3,084,806
368.00	LINE TRANSFORMERS	659,075,934	2.02%	13,304,213	2.42%	15,949,601	2.31%	15,237,900	-0.11%	-711,701
369.00	SERVICES	1,586,331	2.09%	33,167	2.03%	32,280	1.96%	31,152	-0.07%	-1,128
369.10	SERVICES - UNDERGROUND	219,644,701	1.17%	2,571,968	1.15%	2,531,957	1.07%	2,356,101	-0.08%	-175,856
369.20	SERVICES - OVERHEAD	44,053,223	0.67%	297,050	0.62%	271,192	0.54%	237,110	-0.08%	-34,082
370.00	METERS	66,583,470	2.53%	1,683,519	0.34%	229,202	0.30%	201,991	-0.04%	-27,211
370.20	METERS - AMI	147,375,899	6.54%	9,633,232	6.20%	9,130,524	6.09%	8,982,042	-0.11%	-148,482
370.70	EV CHARGER/METER	3,715,623	0.00%	0	10.93%	406,205	10.98%	407,839	0.05%	1,634
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	38,289,054	1.77%	677,631	5.35%	2,050,126	5.06%	1,939,210	-0.29%	-110,916
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	64,756,216	1.65%	1,066,329	3.61%	2,340,175	3.61%	2,339,437	0.00%	-738
	Total Distribution Plant	**4,670,120,248**	**2.22%**	**103,511,101**	**2.84%**	**132,474,796**	**2.34%**	**109,181,746**	**-0.50%**	**-23,293,050**
	GENERAL PLANT									
390.00	STRUCTURES AND IMPROVEMENTS	333,096,941	1.38%	4,597,498	2.22%	7,409,702	2.12%	7,065,046	-0.10%	-344,656
391.00	OFFICE FURNITURE AND EQUIPMENT	22,901,997	6.00%	1,374,380	2.75%	630,778	2.76%	631,095	0.01%	317
391.10	OFFICE FURNITURE AND EQUIPMENT - EDP	55,326,129	21.34%	11,805,007	22.27%	12,323,872	22.16%	12,261,317	-0.11%	-62,555
392.00	TRANSPORTATION EQUIPMENT	17,041,261	3.22%	548,693	3.55%	604,588	3.55%	604,240	0.00%	-348
393.00	STORES EQUIPMENT	883,354	4.27%	37,713	4.65%	41,037	4.66%	41,121	0.01%	84
393.10	FORKLIFTS	1,137,596	3.99%	45,441	3.92%	44,640	3.93%	44,688	0.01%	48

Detailed Rate Comparison

		[1]	[2]		[3]		[4]		[5]	
			Current Parameters		DEI Position		OUCC Position		OUCC Adjustment	
Account No.	**Description**	**Plant 6/30/2023**	**Rate**	**Annual Accrual**	**Rate**	**Annual Accrual**	**Rate**	**Annual Accrual**	**Rate**	**Annual Accrual**
394.00	TOOLS,SHOPS AND GARAGE EQUIPMENT	58,336,673	3.89%	2,267,684	4.68%	2,732,954	4.69%	2,735,997	0.01%	3,043
394.70	EV CHARGER	137,949	0.00%	0	6.73%	9,284	6.75%	9,315	0.02%	31
395.00	LABORATORY EQUIPMENT	99,661	0.00%	0	1.33%	1,330	1.33%	1,330	0.00%	0
396.00	POWER OPERATED EQUIPMENT	7,178,267	4.90%	352,092	3.53%	253,557	3.53%	253,237	0.00%	-320
397.00	COMMUNICATION EQUIPMENT	261,827,247	4.35%	11,394,900	5.39%	14,104,024	5.39%	14,118,682	0.00%	14,658
398.00	MISCELLANEOUS EQUIPMENT	12,685,570	1.18%	149,950	6.42%	813,878	6.41%	813,249	-0.01%	-629
	Total General Plant	**770,652,643**	**4.23%**	**32,573,358**	**5.06%**	**38,969,644**	**5.01%**	**38,579,317**	**-0.05%**	**-390,327**
	TOTAL DEPRECIABLE PLANT	**$ 16,929,597,634**	**3.38%**	**$ 571,990,469**	**4.92%**	**$ 832,738,785**	**4.19%**	**$ 710,009,975**	**-0.72%**	**$ (122,728,810)**

[1], [2] From depreciation study
[3] See response to OUCC 1.9-A
[4] From Attachment DJG-2-4
[5] = [4] - [3]

Depreciation Rate Development

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Account No.	Description	Plant 6/30/2023	Iowa Curve Type AL	Net Salvage	Depreciable Base	Book Reserve	Future Accruals	Remaining Life	Total Accrual	Total Rate
	STEAM PRODUCTION PLANT									
311.00	Structures & Improvements									
	WABASHRIVER COMMON 2-6	73	R2.5 - 100	0%	73	73	0		0	**0.00%**
	CAYUGA UNIT 1	3,660,507	R2.5 - 100	-6%	3,880,137	1,545,330	2,334,807	4.90	476,491	**13.02%**
	CAYUGA UNIT 2	1,306,401	R2.5 - 100	-6%	1,384,785	540,612	844,173	5.90	143,080	**10.95%**
	CAYUGA COMMON 1-2	130,963,099	R2.5 - 100	-6%	138,820,885	60,218,265	78,602,620	5.90	13,322,478	**10.17%**
	CAYUGA INLAND CONTAINER	756,820	R2.5 - 100	-6%	802,230	466,978	335,252	5.90	56,822	**7.51%**
	GIBSON UNIT 1	21,582,707	R2.5 - 100	-8%	23,309,323	11,682,473	11,626,850	14.50	801,852	**3.72%**
	GIBSON UNIT 2	26,001,504	R2.5 - 100	-8%	28,081,624	14,333,055	13,748,569	14.50	948,177	**3.65%**
	GIBSON UNIT 3	34,958,924	R2.5 - 100	-8%	37,755,638	21,299,405	16,456,233	10.70	1,537,966	**4.40%**
	GIBSON UNIT 4	27,554,894	R2.5 - 100	-8%	29,759,285	16,349,492	13,409,793	10.70	1,253,252	**4.55%**
	GIBSON UNIT 5	24,991,190	R2.5 - 100	-8%	26,990,485	14,965,027	12,025,458	6.90	1,742,820	**6.97%**
	GIBSON 3 FLUE GAS	391,692	R2.5 - 100	-8%	423,027	228,236	194,791	10.80	18,036	**4.60%**
	GIBSON 4 FLUE GAS	33,626,121	R2.5 - 100	-8%	36,316,210	19,341,362	16,974,848	10.80	1,571,745	**4.67%**
	GIBSON 5 FLUE GAS	2,537,916	R2.5 - 100	-8%	2,740,949	1,591,547	1,149,402	6.90	166,580	**6.56%**
	GIBSON COMMON 1-2	9,648,571	R2.5 - 100	-8%	10,420,457	3,952,837	6,467,620	14.70	439,974	**4.56%**
	GIBSON COMMON 1-3	81,727,067	R2.5 - 100	-8%	88,265,232	31,749,684	56,515,548	14.70	3,844,595	**4.70%**
	GIBSON COMMON 1-4	6,992,763	R2.5 - 100	-8%	7,552,184	880,090	6,672,094	14.80	450,817	**6.45%**
	GIBSON COMMON 1-5	222,709,671	R2.5 - 100	-8%	240,526,444	64,696,745	175,829,699	14.80	11,880,385	**5.33%**
	GIBSON COMMON 3-4	1,865,692	R2.5 - 100	-8%	2,014,947	811,370	1,203,577	10.80	111,442	**5.97%**
	GIBSON COMMON 4-5	10,505,774	R2.5 - 100	-8%	11,346,235	5,867,726	5,478,509	10.80	507,269	**4.83%**
	GIBSON COMMON 3-5	1,870,726	R2.5 - 100	-8%	2,020,384	940,187	1,080,197	10.80	100,018	**5.35%**
	Total 311.00	643,652,111		-8%	692,410,538	271,460,494	420,950,044	10.69	39,373,801	**6.12%**
311.20	Structures & Improvements - Edwardsport IGCC									
	EDWARDSPORT IGCC	160,837,704	R1.5 - 70	-9%	175,313,097	43,287,877	132,025,220	21.00	6,286,915	**3.91%**
	Total 311.20	160,837,704		-9%	175,313,097	43,287,877	132,025,220	21.00	6,286,915	**3.91%**
312.00	Boiler Plant Equipment									
	CAYUGA UNIT 1	504,617,020	S0.5 - 45	-6%	534,894,041	333,099,414	201,794,626	4.80	42,040,547	**8.33%**
	CAYUGA UNIT 2	458,072,527	S0.5 - 45	-6%	485,556,879	290,861,710	194,695,169	5.80	33,568,133	**7.33%**
	CAYUGA COMMON 1-2	189,314,863	S0.5 - 45	-6%	200,673,754	94,642,107	106,031,647	5.80	18,281,319	**9.66%**
	CAYUGA INLAND CONTAINER	2,437,060	S0.5 - 45	-6%	2,583,284	1,980,052	603,232	5.30	113,817	**4.67%**
	GIBSON UNIT 1	345,666,475	S0.5 - 45	-8%	373,319,793	171,032,097	202,287,696	13.60	14,874,095	**4.30%**
	GIBSON UNIT 2	338,180,652	S0.5 - 45	-8%	365,235,104	171,687,797	193,547,307	13.60	14,231,420	**4.21%**
	GIBSON UNIT 3	344,645,832	S0.5 - 45	-8%	372,217,499	201,486,290	170,731,209	10.30	16,575,846	**4.81%**
	GIBSON UNIT 4	356,121,395	S0.5 - 45	-8%	384,611,107	197,685,775	186,925,332	10.30	18,148,090	**5.10%**
	GIBSON UNIT 5	173,942,835	S0.5 - 45	-8%	187,858,262	113,284,723	74,573,539	6.60	11,299,021	**6.50%**
	GIBSON 1 FLUE GAS	140,265,808	S0.5 - 45	-8%	151,487,073	78,569,437	72,917,636	13.60	5,361,591	**3.82%**
	GIBSON 2 FLUE GAS	146,447,392	S0.5 - 45	-8%	158,163,184	82,167,985	75,995,199	13.60	5,587,882	**3.82%**
	GIBSON 3 FLUE GAS	209,164,024	S0.5 - 45	-8%	225,897,146	137,754,439	88,142,707	10.20	8,641,442	**4.13%**
	GIBSON 4 FLUE GAS	137,645,340	S0.5 - 45	-8%	148,656,968	95,950,028	52,706,940	9.90	5,323,933	**3.87%**
	GIBSON 5 FLUE GAS	59,525,035	S0.5 - 45	-8%	64,287,038	40,784,385	23,502,653	6.60	3,561,008	**5.98%**
	GIBSON COMMON 1-2	7,027,590	S0.5 - 45	-8%	7,589,798	3,279,976	4,309,822	13.40	321,628	**4.58%**
	GIBSON COMMON 1-3	248,486,696	S0.5 - 45	-8%	268,365,632	99,475,069	168,890,563	14.00	12,063,612	**4.85%**
	GIBSON COMMON 1-4	8,633,960	S0.5 - 45	-8%	9,324,677	1,504,478	7,820,199	14.40	543,069	**6.29%**
	GIBSON COMMON 1-5	121,306,607	S0.5 - 45	-8%	131,011,136	48,770,409	82,240,727	13.80	5,959,473	**4.91%**
	GIBSON COMMON 3-4	11,084,456	S0.5 - 45	-8%	11,971,213	8,265,414	3,705,799	9.30	398,473	**3.59%**

Depreciation Rate Development

		[1]	[2]		[3]	[4]	[5]	[6]	[7]	[8]	[9]
Account No.	Description	Plant 6/30/2023	Iowa Curve Type	AL	Net Salvage	Depreciable Base	Book Reserve	Future Accruals	Remaining Life	Total Accrual	Rate
	GIBSON COMMON 4-5	9,654,561	S0.5	45	-8%	10,426,926	7,109,577	3,317,349	9.60	345,557	**3.58%**
	GIBSON COMMON 3-5	1,685,960	S0.5	45	-8%	1,820,837	438,311	1,382,526	10.70	129,208	**7.66%**
	Total 312.00	3,813,926,090			-7%	4,095,951,348	2,179,829,473	1,916,121,875	8.82	217,369,164	**5.70%**
312.10	Boiler Plant Equipment - Coal Cars										
	GIBSON COMMON 1-5	2,914,385	S3	35	-8%	3,147,535	2,107,352	1,040,184	11.00	94,562	**3.24%**
	Total 312.10	2,914,385			-8%	3,147,535	2,107,352	1,040,184	11.00	94,562	**3.24%**
312.20	Boiler Plant Equipment - Edwardsport IGCC										
	EDWARDSPORT IGCC	1,846,072,348	S1	24	-9%	2,012,218,860	667,850,026	1,344,368,833	14.40	93,358,947	**5.06%**
	Total 312.20	1,846,072,348			-9%	2,012,218,860	667,850,026	1,344,368,833	14.40	93,358,947	**5.06%**
312.30	Boiler Plant Equipment - SCR Catalyst										
	GIBSON UNIT 1	3,241,112	S1	15	-8%	3,500,401	2,124,559	1,375,842	5.00	275,168	**8.49%**
	GIBSON UNIT 2	6,189,864	S1	15	-8%	6,685,053	4,821,933	1,863,120	3.00	621,040	**10.03%**
	GIBSON UNIT 3	5,652,917	S1	15	-8%	6,105,150	4,587,536	1,517,614	2.60	583,698	**10.33%**
	GIBSON UNIT 4	2,389,346	S1	15	-8%	2,580,493	1,441,788	1,138,705	6.30	180,747	**7.56%**
	GIBSON UNIT 5	2,528,243	S1	15	-8%	2,730,503	1,765,584	964,919	4.00	241,230	**9.54%**
	Total 312.30	20,001,482			-8%	21,601,600	14,741,400	6,860,200	3.61	1,901,883	**9.51%**
314.00	Turbogenerator Units										
	CAYUGA UNIT 1	48,635,231	S1	55	-6%	51,553,345	27,781,988	23,771,357	4.80	4,952,366	**10.18%**
	CAYUGA UNIT 2	49,013,609	S1	55	-6%	51,954,425	28,059,734	23,894,691	5.80	4,119,774	**8.41%**
	CAYUGA COMMON 1-2	18,608,100	S1	55	-6%	19,724,586	12,347,303	7,377,283	5.70	1,294,260	**6.96%**
	GIBSON UNIT 1	59,983,200	S1	55	-8%	64,781,856	28,318,181	36,463,675	14.10	2,586,076	**4.31%**
	GIBSON UNIT 2	58,505,120	S1	55	-8%	63,185,529	29,037,195	34,148,334	14.00	2,439,167	**4.17%**
	GIBSON UNIT 3	60,214,945	S1	55	-8%	65,032,141	35,385,839	29,646,302	10.40	2,850,606	**4.73%**
	GIBSON UNIT 4	65,438,100	S1	55	-8%	70,673,148	35,249,956	35,423,192	10.50	3,373,637	**5.16%**
	GIBSON UNIT 5	37,070,734	S1	55	-8%	40,036,393	23,281,541	16,754,852	6.70	2,500,724	**6.75%**
	GIBSON COMMON 1-2	3,242,254	S1	55	-8%	3,501,634	1,745,666	1,755,968	13.50	130,072	**4.01%**
	GIBSON COMMON 1-4	1,520,129	S1	55	-8%	1,641,739	221,999	1,419,740	14.80	95,928	**6.31%**
	GIBSON COMMON 1-5	6,579,530	S1	55	-8%	7,105,892	1,586,703	5,519,189	14.40	383,277	**5.83%**
	GIBSON COMMON 3-4	434,495	S1	55	-8%	469,255	153,315	315,940	10.60	29,806	**6.86%**
	GIBSON COMMON 3-5	2,736,096	S1	55	-8%	2,954,984	1,662,406	1,292,578	10.20	126,723	**4.63%**
	Total 314.00	411,981,542			-7%	442,614,927	224,831,826	217,783,101	8.75	24,882,417	**6.04%**
314.20	Turbogenerator Units - Edwardsport IGCC										
	EDWARDSPORT IGCC	589,452,381	S0.5	14	-9%	642,503,095	200,767,833	441,735,262	7.30	60,511,680	**10.27%**
	Total 314.20	589,452,381			-9%	642,503,095	200,767,833	441,735,262	7.30	60,511,680	**10.27%**
314.30	PRIME MOVERS - EDWARDSPORT IGCC										
	EDWARDSPORT IGCC	90,429,354	S1.5	30	-9%	98,567,996	30,820,297	67,747,699	19.70	3,438,969	**3.80%**
	Total 314.30	90,429,354			-9%	98,567,996	30,820,297	67,747,699	19.70	3,438,969	**3.80%**

Depreciation Rate Development

		[1]	[2]		[3]	[4]	[5]	[6]	[7]	[8]	[9]
			Iowa Curve							Total	
Account No.	Description	Plant 6/30/2023	Type	AL	Net Salvage	Depreciable Base	Book Reserve	Future Accruals	Remaining Life	Accrual	Rate
315.00	Accessory Electrical Equipment										
	CAYUGA UNIT 1	10,460,175	R1.5	70	-6%	11,087,786	5,731,001	5,356,785	4.80	1,115,997	**10.67%**
	CAYUGA UNIT 2	8,684,941	R1.5	70	-6%	9,206,037	4,398,138	4,807,899	5.80	828,948	**9.54%**
	CAYUGA COMMON 1-2	3,993,949	R1.5	70	-6%	4,233,586	1,907,471	2,326,115	5.80	401,054	**10.04%**
	CAYUGA INLAND CONTAINER	232,950	R1.5	70	-6%	246,927	180,873	66,054	5.70	11,588	**4.97%**
	GIBSON UNIT 1	16,672,670	R1.5	70	-8%	18,006,483	8,449,241	9,557,242	14.30	668,339	**4.01%**
	GIBSON UNIT 2	21,650,224	R1.5	70	-8%	23,382,242	11,550,846	11,831,396	14.30	827,370	**3.82%**
	GIBSON UNIT 3	16,283,732	R1.5	70	-8%	17,586,430	11,157,786	6,428,644	10.40	618,139	**3.80%**
	GIBSON UNIT 4	12,666,711	R1.5	70	-8%	13,680,048	7,877,745	5,802,303	10.50	552,600	**4.36%**
	GIBSON UNIT 5	15,781,369	R1.5	70	-8%	17,043,879	10,744,428	6,299,451	6.80	926,390	**5.87%**
	GIBSON 4 FLUE GAS	8,299,265	R1.5	70	-8%	8,963,206	5,895,650	3,067,556	10.50	292,148	**3.52%**
	GIBSON 5 FLUE GAS	2,138,719	R1.5	70	-8%	2,309,817	1,647,119	662,698	6.70	98,910	**4.62%**
	GIBSON COMMON 1-2	719,765	R1.5	70	-8%	777,347	108,426	668,921	14.60	45,816	**6.37%**
	GIBSON COMMON 1-3	1,159,798	R1.5	70	-8%	1,252,582	772,055	480,527	14.10	34,080	**2.94%**
	GIBSON COMMON 1-4	78,568	R1.5	70	-8%	84,854	53,128	31,726	14.10	2,250	**2.86%**
	GIBSON COMMON 1-5	15,536,546	R1.5	70	-8%	16,779,470	5,811,448	10,968,022	14.40	761,668	**4.90%**
	GIBSON COMMON 3-4	309,196	R1.5	70	-8%	333,932	121,920	212,012	10.70	19,814	**6.41%**
	GIBSON COMMON 3-5	247,472	R1.5	70	-8%	267,270	44,912	222,358	10.70	20,781	**8.40%**
	GIBSON COMMON 4-5	331,977	R1.5	70	-8%	358,535	254,965	103,570	10.40	9,959	**3.00%**
	Total 315.00	135,248,027			-8%	145,600,429	76,707,152	68,893,277	9.52	7,235,852	**5.35%**
315.20	Accessory Electric Equipment - Edwardsport IGCC										
	EDWARDSPORT IGCC	44,354,359	R2	35	-9%	48,346,251	11,858,035	36,488,216	19.20	1,900,428	**4.28%**
	Total 315.20	44,354,359			-9%	48,346,251	11,858,035	36,488,216	19.20	1,900,428	**4.28%**
316.00	Miscellaneous Power Plant Equip.										
	NOBLESVILLE	29,251	R1	55	-3%	30,129	1,875	28,254	11.50	2,457	**8.40%**
	CAYUGA UNIT 1	8,852,202	R1	55	-6%	9,383,334	5,877,619	3,505,715	4.80	730,357	**8.25%**
	CAYUGA UNIT 2	7,042,084	R1	55	-6%	7,464,609	4,917,037	2,547,572	5.70	446,942	**6.35%**
	CAYUGA COMMON 1-2	19,695,159	R1	55	-6%	20,876,868	9,694,252	11,182,616	5.80	1,928,037	**9.79%**
	CAYUGA INLAND CONTAINER	144,121	R1	55	-6%	152,768	104,406	48,362	5.70	8,485	**5.89%**
	GIBSON UNIT 1	7,098,118	R1	55	-8%	7,665,968	3,650,413	4,015,555	14.00	286,825	**4.04%**
	GIBSON UNIT 2	4,804,584	R1	55	-8%	5,188,951	2,775,735	2,413,216	13.80	174,871	**3.64%**
	GIBSON UNIT 3	7,511,336	R1	55	-8%	8,112,243	4,994,939	3,117,304	10.30	302,651	**4.03%**
	GIBSON UNIT 4	7,789,994	R1	55	-8%	8,413,193	5,136,427	3,276,766	10.30	318,133	**4.08%**
	GIBSON UNIT 5	3,950,101	R1	55	-8%	4,266,109	2,656,792	1,609,317	6.70	240,197	**6.08%**
	GIBSON 4 FLUE GAS	1,156,459	R1	55	-8%	1,248,976	690,056	558,920	10.50	53,230	**4.60%**
	GIBSON 5 FLUE GAS	1,658,109	R1	55	-8%	1,790,758	1,125,877	664,881	6.70	99,236	**5.98%**
	GIBSON COMMON 1-2	1,622,535	R1	55	-8%	1,752,338	1,035,426	716,912	13.60	52,714	**3.25%**
	GIBSON COMMON 1-3	217,962	R1	55	-8%	235,398	123,782	111,616	13.90	8,030	**3.68%**
	GIBSON COMMON 1-4	10,945,997	R1	55	-8%	11,821,676	3,313,418	8,508,258	14.20	599,173	**5.47%**
	GIBSON COMMON 1-5	33,496,416	R1	55	-8%	36,176,130	16,624,011	19,552,119	13.90	1,406,627	**4.20%**
	GIBSON COMMON 3-4	114,216	R1	55	-8%	123,353	87,299	36,054	9.80	3,679	**3.22%**
	GIBSON COMMON 3-5	34,328	R1	55	-8%	37,074	6,295	30,779	10.60	2,904	**8.46%**
	GIBSON COMMON 4-5	12,729	R1	55	-8%	13,748	8,895	4,853	10.30	471	**3.70%**
	Total 316.00	116,175,700			-7%	124,753,622	62,824,554	61,929,069	9.29	6,665,019	**5.74%**
316.20	Misc. Power Plant Equipment - Edwardsport IGCC										

Depreciation Rate Development

Account No.	Description	[1] Plant 6/30/2023	[2] Iowa Curve Type	AL	[3] Net Salvage	[4] Depreciable Base	[5] Book Reserve	[6] Future Accruals	[7] Remaining Life	[8] Total Accrual	[9] Rate
	EDWARDSPORT IGCC	18,853,854	R1.5	35	-9%	20,550,701	3,496,131	17,054,570	19.40	879,102	**4.66%**
	Total 316.20	18,853,854			-9%	20,550,701	3,496,131	17,054,570	19.40	879,102	**4.66%**
	Total Steam Production Plant	7,893,899,337			-8%	8,523,579,999	3,790,582,450	4,732,997,550	10.20	463,898,740	**5.88%**
	HYDRAULIC PRODUCTION PLANT										
331.00	Structures & Improvements	4,649,452	R3	110	-9%	5,067,902	4,343,083	724,819	37.50	19,329	**0.42%**
332.00	Reservoirs, Dams & Waterways	16,001,334	R3	90	-9%	17,441,454	14,716,538	2,724,916	36.90	73,846	**0.46%**
333.00	Waterwheels, Turbines & Generators	126,005,807	R2	50	-9%	137,346,330	9,773,972	127,572,357	33.80	3,774,330	**3.00%**
334.00	Accessory Electrical Equip.	8,480,936	R2	50	-9%	9,244,220	259,472	8,984,748	33.70	266,610	**3.14%**
335.00	Misc. Power Plant Equip.	1,794,412	R2	40	-9%	1,955,909	851,634	1,104,275	30.40	36,325	**2.02%**
	Total Hydraulic Production Plant	156,931,940			-9%	171,055,815	29,944,700	141,111,115	33.84	4,170,439	**2.66%**
	OTHER PRODUCTION PLANT										
341.00	Structures & Improvements										
	NOBLESVILLE	16,410,639	R3	50	-3%	16,902,959	11,300,537	5,602,422	10.80	518,743	**3.16%**
	NOBLESVILLE CT UNIT 3	3,163,542	R3	50	-3%	3,258,449	2,288,952	969,497	11.50	84,304	**2.66%**
	NOBLESVILLE CT UNIT 4	3,163,275	R3	50	-3%	3,258,173	2,288,839	969,334	11.50	84,290	**2.66%**
	NOBLESVILLE CT UNIT 5	3,182,777	R3	50	-3%	3,278,261	2,302,038	976,223	11.50	84,889	**2.67%**
	VERMILLION CT STATION	4,966,083	R3	50	-4%	5,164,727	2,790,063	2,374,664	18.10	131,197	**2.64%**
	CAYUGA CT UNIT 4	5,776,462	R3	50	-4%	6,007,520	4,156,907	1,850,613	11.90	155,514	**2.69%**
	CINCAP MADISON CT 1-8	10,493,056	R3	50	-4%	10,912,778	5,745,357	5,167,421	16.70	309,426	**2.95%**
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	6,096,749	R3	50	-5%	6,401,586	3,357,933	3,043,653	14.30	212,843	**3.49%**
	CAYUGA DIESEL	5,515	R3	50	-4%	5,735	5,166	569	4.90	116	**2.11%**
	WHEATLAND CT UNIT 1	28,000	R3	50	-5%	29,400	14,108	15,292	18.70	818	**2.92%**
	WHEATLAND CT UNIT 2	28,000	R3	50	-5%	29,400	14,108	15,292	18.70	818	**2.92%**
	WHEATLAND CT UNIT 3	251,291	R3	50	-5%	263,855	29,744	234,111	19.60	11,944	**4.75%**
	WHEATLAND CT UNIT 4	28,000	R3	50	-5%	29,400	14,108	15,292	18.70	818	**2.92%**
	WHEATLAND COMMON CT 1-4	1,183,850	R3	50	-5%	1,243,042	343,151	899,891	19.40	46,386	**3.92%**
	PURDUE CHP	14,589,461	R3	50	-4%	15,173,040	426,899	14,746,141	32.30	456,537	**3.13%**
	Total 341.00	69,366,700			-4%	71,958,325	35,077,910	36,880,415	17.57	2,098,642	**3.03%**
341.66	STRUCTURES AND IMPROVEMENTS - SOLAR										
	CRANE SOLAR	401,873	R2.5	45	-4%	417,948	155,841	262,107	22.60	11,598	**2.89%**
	Total 341.66	401,873			-4%	417,948	155,841	262,107	22.60	11,598	**2.89%**
342.00	Fuel Holders, Producers and Accessories										
	NOBLESVILLE	659,972	R4	55	-3%	679,771	259,615	420,156	11.90	35,307	**5.35%**
	NOBLESVILLE CT UNIT 3	44,569	R4	55	-3%	45,906	37,741	8,165	11.80	692	**1.55%**
	NOBLESVILLE CT UNIT 4	306,714	R4	55	-3%	315,916	115,393	200,523	11.90	16,851	**5.49%**
	NOBLESVILLE CT UNIT 5	152,543	R4	55	-3%	157,119	81,115	76,004	11.90	6,387	**4.19%**
	NOBLESVILLE COMMON 3-5	6,749,463	R4	55	-3%	6,951,947	6,095,207	856,740	11.80	72,605	**1.08%**
	VERMILLION CT STATION	21,309,587	R4	55	-4%	22,161,970	14,717,100	7,444,870	19.00	391,835	**1.84%**

Depreciation Rate Development

Account No.	Description	[1] Plant 6/30/2023	[2] Iowa Curve Type	AL	[3] Net Salvage	[4] Depreciable Base	[5] Book Reserve	[6] Future Accruals	[7] Remaining Life	[8] Total Accrual	[9] Rate
	CAYUGA CT UNIT 4	2,868,642	R4	55	-4%	2,983,387	2,480,670	502,717	12.50	40,217	**1.40%**
	CINCAP MADISON CT 1-8	9,285,364	R4	55	-4%	9,656,778	6,800,093	2,856,685	17.20	166,086	**1.79%**
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	785,745	R4	55	-5%	825,032	378,757	446,275	14.80	30,154	**3.84%**
	CAYUGA DIESEL	25,530	R4	55	-4%	26,552	27,062	-510			
	WHEATLAND CT UNIT 1	110,000	R4	55	-5%	115,500	68,957	46,543	19.40	2,399	**2.18%**
	WHEATLAND CT UNIT 2	145,404	R4	55	-5%	152,674	61,948	90,726	19.80	4,582	**3.15%**
	WHEATLAND CT UNIT 3	110,000	R4	55	-5%	115,500	68,957	46,543	19.40	2,399	**2.18%**
	WHEATLAND CT UNIT 4	110,000	R4	55	-5%	115,500	68,957	46,543	19.40	2,399	**2.18%**
	WHEATLAND COMMON CT 1-4	825,592	R4	55	-5%	866,872	460,569	406,303	19.50	20,836	**2.52%**
	PURDUE CHP	832,096	R4	55	-4%	865,380	562,467	302,913	33.30	9,096	**1.09%**
	Total 342.00	44,321,221			-4%	46,035,805	32,284,608	13,751,197	17.15	801,847	**1.81%**
343.00	Prime Movers										
	NOBLESVILLE	41,775,759	S0.5	40	-3%	43,029,032	20,624,148	22,404,884	11.00	2,036,808	**4.88%**
	NOBLESVILLE CT UNIT 3	39,803,772	S0.5	40	-3%	40,997,885	22,993,304	18,004,581	10.80	1,667,091	**4.19%**
	NOBLESVILLE CT UNIT 4	37,186,697	S0.5	40	-3%	38,302,298	21,814,491	16,487,807	10.80	1,526,649	**4.11%**
	NOBLESVILLE CT UNIT 5	38,689,635	S0.5	40	-3%	39,850,324	21,546,602	18,303,722	10.90	1,679,241	**4.34%**
	VERMILLION CT STATION	11,982,114	S0.5	40	-4%	12,461,398	2,225,928	10,235,470	18.10	565,496	**4.72%**
	CAYUGA CT UNIT 4	31,337,960	S0.5	40	-4%	32,591,478	17,513,713	15,077,765	11.10	1,358,357	**4.33%**
	CINCAP MADISON CT UNIT 5	452,491	S0.5	40	-4%	470,591	22,644	447,947	17.10	26,196	**5.79%**
	CINCAP MADISON CT 1-8	205,898,963	S0.5	40	-4%	214,134,922	99,785,679	114,349,243	14.80	7,726,300	**3.75%**
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	48,047,008	S0.5	40	-5%	50,449,358	20,963,504	29,485,854	13.40	2,200,437	**4.58%**
	WHEATLAND CT UNIT 1	24,479,523	S0.5	40	-5%	25,703,500	8,179,522	17,523,978	17.40	1,007,125	**4.11%**
	WHEATLAND CT UNIT 2	16,265,414	S0.5	40	-5%	17,078,685	6,234,610	10,844,075	16.90	641,661	**3.94%**
	WHEATLAND CT UNIT 3	13,916,184	S0.5	40	-5%	14,611,993	5,375,142	9,236,851	16.90	546,559	**3.93%**
	WHEATLAND CT UNIT 4	16,871,646	S0.5	40	-5%	17,715,228	7,078,855	10,636,373	16.60	640,745	**3.80%**
	WHEATLAND COMMON CT 1-4	1,339,096	S0.5	40	-5%	1,406,051	327,700	1,078,351	18.00	59,908	**4.47%**
	PURDUE CHP	16,000,278	S0.5	40	-4%	16,640,289	888,382	15,751,907	28.60	550,766	**3.44%**
	Total 343.00	544,046,540			-4%	565,443,032	255,574,224	309,868,808	13.94	22,233,339	**4.09%**
343.10	PRIME MOVERS - ROTABLE PARTS										
	NOBLESVILLE	1,245,752	R3	13	-3%	1,283,124	1,457,530	-174,406			
	NOBLESVILLE CT UNIT 3	15,741,851	R3	13	-3%	16,214,107	15,079,801	1,134,306	9.50	119,401	**0.76%**
	NOBLESVILLE CT UNIT 4	15,399,004	R3	13	-3%	15,860,974	11,576,680	4,284,294	10.10	424,188	**2.75%**
	NOBLESVILLE CT UNIT 5	14,298,975	R3	13	-3%	14,727,944	12,124,801	2,603,143	9.20	282,950	**1.98%**
	VERMILLION CT STATION	9,622,671	R3	13	-4%	10,007,578	8,858,181	1,149,397	10.80	106,426	**1.11%**
	CINCAP MADISON CT UNIT 5	1,573,076	R3	13	-4%	1,635,999	321,873	1,314,126	12.00	109,510	**6.96%**
	CINCAP MADISON CT 1-8	32,132,531	R3	13	-4%	33,417,832	33,543,149	-125,317	12.00	-10,443	**-0.03%**
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	9,550,566	R3	13	-5%	10,028,094	10,309,045	-280,951	11.70	-24,013	**-0.25%**
	WHEATLAND CT UNIT 2	8,705,071	R3	13	-5%	9,140,324	2,004,731	7,135,593	12.00	594,633	**6.83%**
	WHEATLAND CT UNIT 3	10,897,303	R3	13	-5%	11,442,168	9,783,004	1,659,164	9.20	180,344	**1.65%**
	WHEATLAND CT UNIT 4	1,862,583	R3	13	-5%	1,955,712	1,672,125	283,587	9.20	30,825	**1.65%**
	PURDUE CHP	1,908,792	R3	13	-4%	1,985,143	500,507	1,484,636	11.10	133,751	**7.01%**
	Total 343.10	122,938,174			-4%	127,699,000	107,231,427	20,467,573	10.51	1,947,571	**1.58%**
344.00	GENERATORS										
	NOBLESVILLE	32,216,844	S2	50	-3%	33,183,350	28,598,205	4,585,145	11.60	395,271	**1.23%**
	NOBLESVILLE CT UNIT 3	4,810,989	S2	50	-3%	4,955,319	1,964,170	2,991,149	11.90	251,357	**5.22%**

Depreciation Rate Development

Account No.	Description	[1] Plant 6/30/2023	[2] Iowa Curve Type - AL	[3] Net Salvage	[4] Depreciable Base	[5] Book Reserve	[6] Future Accruals	[7] Remaining Life	[8] Total Accrual	[9] Total Rate
	NOBLESVILLE CT UNIT 4	3,720,635	S2 - 50	-3%	3,832,254	1,930,111	1,902,143	11.80	161,199	**4.33%**
	NOBLESVILLE CT UNIT 5	2,869,494	S2 - 50	-3%	2,955,579	1,191,917	1,763,662	11.90	148,207	**5.16%**
	VERMILLION CT STATION	117,105,325	S2 - 50	-4%	121,789,538	86,059,744	35,729,794	17.50	2,041,703	**1.74%**
	CAYUGA CT UNIT 4	9,937,169	S2 - 50	-4%	10,334,655	8,600,034	1,734,621	12.10	143,357	**1.44%**
	CINCAP MADISON CT 1-8	70,254,584	S2 - 50	-4%	73,064,767	53,335,619	19,729,148	16.10	1,225,413	**1.74%**
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	25,229,111	S2 - 50	-5%	26,490,567	20,567,838	5,922,729	13.80	429,183	**1.70%**
	CAYUGA DIESEL	1,950,116	S2 - 50	-4%	2,028,121	1,942,861	85,260	5.90	14,451	**0.74%**
	WHEATLAND CT UNIT 1	5,886,136	S2 - 50	-5%	6,180,442	2,335,937	3,844,505	19.20	200,235	**3.40%**
	WHEATLAND CT UNIT 2	4,059,676	S2 - 50	-5%	4,262,660	2,663,474	1,599,186	18.30	87,387	**2.15%**
	WHEATLAND CT UNIT 3	4,059,676	S2 - 50	-5%	4,262,660	2,663,473	1,599,187	18.30	87,387	**2.15%**
	WHEATLAND CT UNIT 4	4,389,971	S2 - 50	-5%	4,609,470	2,610,508	1,998,962	18.60	107,471	**2.45%**
	WHEATLAND COMMON CT 1-4	555,876	S2 - 50	-5%	583,670	105,475	478,195	19.70	24,274	**4.37%**
	PURDUE CHP	12,454,709	S2 - 50	-4%	12,952,897	1,888,361	11,064,536	32.20	343,619	**2.76%**
	Total 344.00	299,500,312		-4%	311,485,949	216,457,727	95,028,222	16.79	5,660,513	**1.89%**
344.66	GENERATORS - SOLAR									
	CRANE SOLAR	32,498,249	S1.5 - 30	-4%	33,798,179	7,864,189	25,933,990	19.80	1,309,797	**4.03%**
	CAMP ATTERBURY MICROGRID	5,395,191	S1.5 - 30	0%	5,412,817	902,879	4,509,938	19.40	232,471	**4.31%**
	Total 344.66	37,893,440		-3%	39,210,996	8,767,068	30,443,928	19.74	1,542,269	**4.07%**
345.00	Accessory Electric Equipment									
	NOBLESVILLE	5,263,616	S0.5 - 40	-3%	5,421,525	3,503,255	1,918,270	11.30	169,758	**3.23%**
	NOBLESVILLE CT UNIT 3	821,222	S0.5 - 40	-3%	845,859	628,303	217,556	10.70	20,332	**2.48%**
	NOBLESVILLE CT UNIT 4	921,731	S0.5 - 40	-3%	949,383	666,308	283,075	10.80	26,211	**2.84%**
	NOBLESVILLE CT UNIT 5	813,419	S0.5 - 40	-3%	837,822	626,903	210,919	10.70	19,712	**2.42%**
	VERMILLION CT STATION	576,013	S0.5 - 40	-4%	599,053	265,513	333,541	18.50	18,029	**3.13%**
	CAYUGA CT UNIT 4	5,276,891	S0.5 - 40	-4%	5,487,967	3,652,121	1,835,846	11.20	163,915	**3.11%**
	CINCAP MADISON CT UNIT 2	50,087	S0.5 - 40	-4%	52,091	20,824	31,267	16.10	1,942	**3.88%**
	CINCAP MADISON CT UNIT 6	46,569	S0.5 - 40	-4%	48,432	19,362	29,070	16.10	1,806	**3.88%**
	CINCAP MADISON CT UNIT 7	48,262	S0.5 - 40	-4%	50,193	20,066	30,127	16.10	1,871	**3.88%**
	CINCAP MADISON CT UNIT 8	48,378	S0.5 - 40	-4%	50,313	20,114	30,199	16.10	1,876	**3.88%**
	CINCAP MADISON CT 1-8	13,378,339	S0.5 - 40	-4%	13,913,472	7,774,108	6,139,364	14.90	412,038	**3.08%**
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	4,974,916	S0.5 - 40	-5%	5,223,661	3,020,468	2,203,193	13.10	168,183	**3.38%**
	CAYUGA DIESEL	872,195	S0.5 - 40	-4%	907,083	638,011	269,072	5.80	46,392	**5.32%**
	WHEATLAND CT UNIT 1	556,463	S0.5 - 40	-5%	584,286	283,884	300,402	16.70	17,988	**3.23%**
	WHEATLAND CT UNIT 2	594,851	S0.5 - 40	-5%	624,593	296,885	327,708	16.80	19,506	**3.28%**
	WHEATLAND CT UNIT 3	525,418	S0.5 - 40	-5%	551,689	273,094	278,595	16.70	16,682	**3.18%**
	WHEATLAND CT UNIT 4	246,761	S0.5 - 40	-5%	259,099	115,136	143,963	17.00	8,468	**3.43%**
	WHEATLAND COMMON CT 1-4	2,019,408	S0.5 - 40	-5%	2,120,378	595,225	1,525,153	18.00	84,731	**4.20%**
	PURDUE CHP	8,899,540	S0.5 - 40	-4%	9,255,522	347,080	8,908,442	28.60	311,484	**3.50%**
	Total 345.00	45,934,080		-4%	47,782,421	22,766,660	25,015,761	16.56	1,510,924	**3.29%**
345.66	ACCESSORY ELECTRIC EQUIPMENT - SOLAR									
	CRANE SOLAR	5,246,980	S2.5 - 30	-4%	5,456,859	655,875	4,800,984	20.60	233,057	**4.44%**
	Total 345.66	5,246,980		-4%	5,456,859	655,875	4,800,984	20.60	233,057	**4.44%**
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT									

Depreciation Rate Development

Account No.	Description	[1] Plant 6/30/2023	[2] Iowa Curve Type	Iowa Curve AL	[3] Net Salvage	[4] Depreciable Base	[5] Book Reserve	[6] Future Accruals	[7] Remaining Life	[8] Total Accrual	[9] Total Rate
	NOBLESVILLE	6,022,969	S0.5	40	-3%	6,203,658	2,618,464	3,585,194	10.70	335,065	**5.56%**
	NOBLESVILLE CT UNIT 3	2,173,761	S0.5	40	-3%	2,238,974	1,100,194	1,138,780	10.80	105,443	**4.85%**
	NOBLESVILLE CT UNIT 4	2,078,917	S0.5	40	-3%	2,141,285	1,083,033	1,058,252	10.70	98,902	**4.76%**
	NOBLESVILLE CT UNIT 5	2,105,949	S0.5	40	-3%	2,169,127	1,082,203	1,086,924	10.80	100,641	**4.78%**
	CAYUGA CT UNIT 4	1,246,913	S0.5	40	-4%	1,296,789	619,098	677,691	11.10	61,053	**4.90%**
	CINCAP MADISON CT 1-8	2,541,817	S0.5	40	-4%	2,643,489	536,135	2,107,354	16.50	127,718	**5.02%**
	HENRY COUNTY COMMON CT 1-3 (CADIZ CINCAP)	1,618,558	S0.5	40	-5%	1,699,486	374,043	1,325,443	14.00	94,674	**5.85%**
	CAYUGA DIESEL	311	S0.5	40	-4%	324	221	103	5.00	21	**6.59%**
	WHEATLAND CT UNIT 1	573,108	S0.5	40	-5%	601,764	209,510	392,254	16.70	23,488	**4.10%**
	WHEATLAND CT UNIT 2	573,663	S0.5	40	-5%	602,346	209,537	392,809	16.70	23,521	**4.10%**
	WHEATLAND CT UNIT 3	579,994	S0.5	40	-5%	608,994	211,779	397,215	16.70	23,785	**4.10%**
	WHEATLAND CT UNIT 4	575,640	S0.5	40	-5%	604,422	209,628	394,794	16.70	23,640	**4.11%**
	WHEATLAND COMMON CT 1-4	3,608,879	S0.5	40	-5%	3,789,323	1,142,082	2,647,241	17.10	154,809	**4.29%**
	PURDUE CHP	323,349	S0.5	40	-4%	336,282	15,880	320,402	28.60	11,203	**3.46%**
	Total 346.00	24,023,827			-4%	24,936,263	9,411,807	15,524,456	13.11	1,183,965	**4.93%**
348.01	BATTERY STORAGE	20,502,681	L3	15	0%	20,502,681	4,453,002	16,049,679	11.60	1,383,593	**6.75%**
	Total Other Production Plant	1,214,175,828			-4%	1,260,929,279	692,836,149	568,093,130	14.71	38,607,318	**3.18%**
	Total Production Plant	**9,265,007,105**			**-7%**	**9,955,565,093**	**4,513,363,298**	**5,442,201,795**	**10.74**	**506,676,497**	**5.47%**
	TRANSMISSION PLANT										
350.10	RIGHTS OF WAY	40,427,081	R4	80	0%	40,427,081	21,849,876	18,577,206	47.40	391,924	**0.97%**
352.00	STRUCTURES AND IMPROVEMENTS	82,753,143	R2.5	70	-5%	86,890,800	11,773,775	75,117,025	59.50	1,262,471	**1.53%**
353.00	STATION EQUIPMENT	909,453,535	R1	54	-11%	1,009,493,424	210,899,698	798,593,726	43.10	18,528,857	**2.04%**
354.00	TOWERS AND FIXTURES	89,256,597	R3	88	-33%	118,711,274	60,498,018	58,213,255	51.49	1,130,574	**1.27%**
355.00	POLES AND FIXTURES	530,518,385	R1	45	-30%	689,673,901	-26,157,859	715,831,760	33.10	21,626,337	**4.08%**
356.00	OVERHEAD CONDUCTORS AND DEVICES	568,924,400	R2	74	-63%	927,346,772	150,899,858	776,446,914	61.85	12,553,709	**2.21%**
357.00	UNDERGROUND CONDUIT	227,876	R2	40	0%	227,876	108,944	118,932	34.10	3,488	**1.53%**
358.00	UNDERGROUND CONDUCTOR AND DEVICES	2,256,621	R3	35	-1%	2,279,187	140,143	2,139,044	28.50	75,054	**3.33%**
	Total Transmission Plant	**2,223,817,638**			**-32%**	**2,875,050,315**	**430,012,453**	**2,445,037,863**	**44.00**	**55,572,414**	**2.50%**
	DISTRIBUTION PLANT										
360.10	RIGHTS OF WAY	5,120,349	R4	75	0%	5,120,349	1,118,073	4,002,276	63.50	63,028	**1.23%**
361.00	STRUCTURES AND IMPROVEMENTS	53,708,979	R2	55	-10%	59,079,876	10,972,936	48,106,940	43.30	1,111,015	**2.07%**
362.00	STATION EQUIPMENT	796,636,440	S0	45	-15%	916,131,906	191,489,534	724,642,373	36.00	20,128,955	**2.53%**
363.01	BATTERY STORAGE	3,265,111	L3	15	0%	3,265,111	338,805	2,926,306	13.00	225,100	**6.89%**
364.00	POLES, TOWERS AND FIXTURES	669,356,236	R0.5	57	-58%	1,057,582,854	250,931,513	806,651,341	47.90	16,840,320	**2.52%**
365.00	OVERHEAD CONDUCTORS AND DEVICES	953,714,828	O3	57	-45%	1,382,886,501	132,200,066	1,250,686,434	55.22	22,649,157	**2.37%**
366.00	UNDERGROUND CONDUIT	76,947,858	R2	60	-25%	96,184,822	8,290,043	87,894,779	51.70	1,700,092	**2.21%**
367.00	UNDERGROUND CONDUCTORS AND DEVICES	866,289,998	R1.5	68	-26%	1,091,525,397	234,900,628	856,624,770	58.15	14,731,294	**1.70%**
368.00	LINE TRANSFORMERS	659,075,934	R0.5	44	-21%	797,481,880	227,584,406	569,897,474	37.40	15,237,900	**2.31%**
369.00	SERVICES	1,586,331	R1	60	-26%	1,998,777	219,978	1,778,799	57.10	31,152	**1.96%**

Depreciation Rate Development

		[1]	[2]		[3]	[4]	[5]	[6]	[7]	[8]	[9]
Account No.	Description	Plant 6/30/2023	Iowa Curve Type	AL	Net Salvage	Depreciable Base	Book Reserve	Future Accruals	Remaining Life	Total Accrual	Total Rate
369.10	SERVICES - UNDERGROUND	219,644,701	R1	60	-26%	276,752,323	158,711,645	118,040,678	50.10	2,356,101	**1.07%**
369.20	SERVICES - OVERHEAD	44,053,223	R1	60	-26%	55,507,061	43,201,040	12,306,021	51.90	237,110	**0.54%**
370.00	METERS	66,583,470	S0.5	25	-1%	67,249,304	62,381,329	4,867,976	24.10	201,991	**0.30%**
370.20	METERS - AMI	147,375,899	S2.5	15	-1%	148,849,658	45,556,172	103,293,486	11.50	8,982,042	**6.09%**
370.70	EV CHARGER/METER	3,715,623	S3	10	0%	3,715,623	45,069	3,670,553	9.00	407,839	**10.98%**
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	38,289,054	L0	20	-11%	42,500,849	15,157,987	27,342,863	14.10	1,939,210	**5.06%**
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	64,756,216	O1	30	-15%	74,469,648	16,919,495	57,550,153	24.60	2,339,437	**3.61%**
	Total Distribution Plant	**4,670,120,248**			**-27%**	**6,080,301,939**	**1,400,018,719**	**4,680,283,221**	**42.87**	**109,181,746**	**2.34%**
	GENERAL PLANT										
390.00	STRUCTURES AND IMPROVEMENTS	333,096,941	R1.5	45	-11%	369,737,604	99,146,348	270,591,256	38.30	7,065,046	**2.12%**
391.00	OFFICE FURNITURE AND EQUIPMENT	22,901,997	SQ	20	0%	22,901,997	13,120,024	9,781,973	15.50	631,095	**2.76%**
391.10	OFFICE FURNITURE AND EQUIPMENT - EDP	55,326,129	SQ	5	0%	55,326,129	13,637,650	41,688,479	3.40	12,261,317	**22.16%**
392.00	TRANSPORTATION EQUIPMENT	17,041,261	L2.5	20	10%	15,337,134	6,454,800	8,882,335	14.70	604,240	**3.55%**
393.00	STORES EQUIPMENT	883,354	SQ	20	0%	883,354	340,554	542,800	13.20	41,121	**4.66%**
393.10	FORKLIFTS	1,137,596	SQ	25	0%	1,137,596	176,809	960,786	21.50	44,688	**3.93%**
394.00	TOOLS,SHOPS AND GARAGE EQUIPMENT	58,336,673	SQ	25	0%	58,336,673	20,579,915	37,756,758	13.80	2,735,997	**4.69%**
394.70	EV CHARGER	137,949	R3	15	0%	137,949	7,540	130,409	14.00	9,315	**6.75%**
395.00	LABORATORY EQUIPMENT	99,661	SQ	20	0%	99,661	90,352	9,309	7.00	1,330	**1.33%**
396.00	POWER OPERATED EQUIPMENT	7,178,267	R1	23	10%	6,460,440	1,066,495	5,393,945	21.30	253,237	**3.53%**
397.00	COMMUNICATION EQUIPMENT	261,827,247	SQ	20	0%	261,827,247	66,989,438	194,837,809	13.80	14,118,682	**5.39%**
398.00	MISCELLANEOUS EQUIPMENT	12,685,570	SQ	15	0%	12,685,570	2,601,278	10,084,292	12.40	813,249	**6.41%**
	Total General Plant	**770,652,643**			**-5%**	**804,871,354**	**224,211,203**	**580,660,151**	**15.05**	**38,579,317**	**5.01%**
	TOTAL DEPRECIABLE PLANT	**$ 16,929,597,634**			**-17%**	**$ 19,715,788,701**	**$ 6,567,605,672**	**$ 13,148,183,029**	**18.52**	**$ 710,009,975**	**4.19%**

[1] From depreciation study
[2] Average life and Iowa curve shape developed through statistical analysis and professional judgment
[3] Mass net salvage rates developed through statistical analysis and professional judgment; terminal net salvage rates for production units are from Attachment DJG-2-5
[4] = [1]*(1-[3])
[5] From depreciation study
[6] = [4] - [5]
[7] Composite remaining life based on Iowa cuve in [2]; see remaining life exhibit for detailed calculations
[8] = [6] / [7]
[9] = [8] / [1]

Weighted Net Salvage

	[1]	[2]	[3]	[4]	[5]
	Terminal Retirements		Interim Retirements		Weighted
Location	Retirements	Net Salvage	Retirements	Net Salvage	Net Salvage
STEAM PRODUCTION					
CAYUGA	95%	-6%	5%	-10%	-6%
EDWARDSPORT	27%	-6%	73%	-10%	-9%
GIBSON	86%	-8%	14%	-10%	-8%
HYDRO PRODUCTION					
MARKLAND	70%	-2%	30%	-24%	-9%
OTHER PRODUCTION					
CAYUGA CT	74%	-2%	26%	-10%	-4%
HENRY COUNTY	72%	-4%	28%	-10%	-5%
MADISON	61%	-1%	39%	-10%	-4%
NOBLESVILLE CT	74%	-1%	26%	-10%	-3%
PURDUE	69%	-1%	31%	-10%	-4%
VERMILLION	69%	-2%	31%	-10%	-4%
WHEATLAND	59%	-1%	41%	-10%	-5%
SOLAR PRODUCTION					
CRANE	52%	-5%	48%	-2%	-4%
ATTERBURY	66%	0%	34%	-2%	-1%

[1], [3] Accepted Company's proposed weighting of interim and terminal retirements (see depreciation study)

[2] From Attachment DJG-2-5

[4] Company's proposed interim net salvage rates from depreciation study

[5] = [1]*[2] + [3]*[4] (rounded)

Terminal Net Salvage Adjustment

Unit	[1] Decommissioning Cost	[2] Coal Ash ARO	[3] Decommissioning Less ARO Cost	[4] Indirect Costs	[5] Contingency Costs	[6] Adjusted Decom Cost	[7] Terminal Retirements	[8] Terminal Net Salvage
STEAM PRODUCTION								
CAYUGA	$ 133,842,000	$ 32,749,824	$ 101,092,176	$ 7,439,000	$ 14,879,000	$ 78,774,176	$ (1,395,427,256)	-6%
EDWARDSPORT	57,546,000	-	57,546,000	5,212,000	10,424,000	41,910,000	(739,148,594)	-6%
GIBSON	378,221,000	46,507,949	331,713,051	28,813,000	57,627,000	245,273,051	(3,263,193,707)	-8%
HYDRO PRODUCTION								
MARKLAND	3,786,000	-	3,786,000	350,000	701,000	2,735,000	(110,448,141)	-2%
OTHER PRODUCTION								
CAYUGA CT	1,398,000	-	1,398,000	153,000	305,000	940,000	(41,917,562)	-2%
HENRY COUNTY	3,476,000	-	3,476,000	350,000	699,000	2,427,000	(68,658,331)	-4%
MADISON	2,844,000	-	2,844,000	566,000	1,132,000	1,146,000	(211,312,002)	-1%
NOBLESVILLE CT	18,732,000	12,817,629	5,914,371	1,414,000	2,829,000	1,671,371	(224,275,131)	-1%
PURDUE	885,000	-	885,000	111,000	221,000	553,000	(38,183,049)	-1%
VERMILLION	3,547,000	-	3,547,000	607,000	1,214,000	1,726,000	(114,800,606)	-2%
WHEATLAND	1,975,000	-	1,975,000	366,000	732,000	877,000	(74,366,453)	-1%
SOLAR PRODUCTION								
CRANE	1,581,200	-	1,581,200	180,500	361,100	1,039,600	(20,007,263)	-5%
ATTERBURY	183,900	-	183,900	22,800	45,600	115,500	(35,353,847)	0%

[1], [3], [4], [5] See Direct Testimony and Exhibits of Jeffrey T. Kopp
[2], [7] See depreciation study
[3] = [1] - [2]
[6] = [3] - [4] - [5]
[8] = [6] / [7]

Account 354 Curve Fitting

[1] Age (Years)	[2] Exposures (Dollars)	[3] Observed Life Table (OLT)	[4] DEI R3-80	[5] OUCC R3-88	[6] DEI SSD	[7] OUCC SSD
0.0	88,147,102	100.00%	100.00%	100.00%	0.0000	0.0000
0.5	88,019,045	99.95%	99.99%	99.99%	0.0000	0.0000
1.5	87,464,801	99.95%	99.97%	99.97%	0.0000	0.0000
2.5	89,934,373	99.95%	99.95%	99.95%	0.0000	0.0000
3.5	89,827,913	99.89%	99.92%	99.93%	0.0000	0.0000
4.5	89,742,238	99.80%	99.89%	99.91%	0.0000	0.0000
5.5	90,327,030	99.80%	99.86%	99.88%	0.0000	0.0000
6.5	89,860,406	99.28%	99.83%	99.85%	0.0000	0.0000
7.5	89,857,971	99.28%	99.79%	99.82%	0.0000	0.0000
8.5	89,839,426	99.25%	99.75%	99.78%	0.0000	0.0000
9.5	89,422,396	99.20%	99.71%	99.74%	0.0000	0.0000
10.5	87,787,048	99.18%	99.66%	99.70%	0.0000	0.0000
11.5	70,857,506	99.16%	99.60%	99.66%	0.0000	0.0000
12.5	70,847,363	99.14%	99.54%	99.61%	0.0000	0.0000
13.5	70,681,922	98.92%	99.48%	99.56%	0.0000	0.0000
14.5	70,575,209	98.76%	99.41%	99.50%	0.0000	0.0001
15.5	70,485,194	98.75%	99.34%	99.44%	0.0000	0.0000
16.5	70,485,194	98.75%	99.26%	99.38%	0.0000	0.0000
17.5	70,478,430	98.74%	99.17%	99.31%	0.0000	0.0000
18.5	72,572,813	98.58%	99.08%	99.23%	0.0000	0.0000
19.5	72,544,974	98.54%	98.97%	99.15%	0.0000	0.0000
20.5	72,333,339	98.25%	98.86%	99.06%	0.0000	0.0001
21.5	70,877,811	96.27%	98.75%	98.97%	0.0006	0.0007
22.5	70,865,295	96.26%	98.62%	98.87%	0.0006	0.0007
23.5	70,490,384	96.25%	98.49%	98.76%	0.0005	0.0006
24.5	70,512,059	96.21%	98.34%	98.65%	0.0005	0.0006
25.5	70,471,940	96.09%	98.19%	98.53%	0.0004	0.0006
26.5	69,453,109	95.82%	98.02%	98.40%	0.0005	0.0007
27.5	69,415,722	95.77%	97.84%	98.26%	0.0004	0.0006
28.5	69,394,506	95.74%	97.65%	98.12%	0.0004	0.0006
29.5	69,298,409	95.60%	97.45%	97.96%	0.0003	0.0006
30.5	69,245,395	95.52%	97.24%	97.80%	0.0003	0.0005
31.5	69,023,812	95.41%	97.01%	97.63%	0.0003	0.0005
32.5	68,755,800	95.40%	96.77%	97.44%	0.0002	0.0004
33.5	68,664,579	95.38%	96.52%	97.25%	0.0001	0.0003
34.5	68,162,425	94.77%	96.25%	97.05%	0.0002	0.0005
35.5	67,995,863	94.61%	95.96%	96.83%	0.0002	0.0005
36.5	66,479,121	94.06%	95.66%	96.60%	0.0003	0.0006
37.5	66,350,667	94.05%	95.34%	96.36%	0.0002	0.0005
38.5	66,175,356	93.86%	95.00%	96.11%	0.0001	0.0005
39.5	65,608,729	93.16%	94.65%	95.84%	0.0002	0.0007
40.5	65,412,450	93.02%	94.28%	95.56%	0.0002	0.0006
41.5	52,451,983	92.69%	93.88%	95.27%	0.0001	0.0007
42.5	50,585,304	92.64%	93.47%	94.96%	0.0001	0.0005
43.5	50,213,343	92.28%	93.03%	94.63%	0.0001	0.0006
44.5	34,756,416	92.15%	92.58%	94.29%	0.0000	0.0005
45.5	32,319,874	91.49%	92.10%	93.94%	0.0000	0.0006
46.5	25,445,983	91.41%	91.60%	93.57%	0.0000	0.0005
47.5	24,453,488	91.40%	91.07%	93.18%	0.0000	0.0003
48.5	16,265,350	91.37%	90.52%	92.77%	0.0001	0.0002
49.5	16,247,192	91.35%	89.94%	92.34%	0.0002	0.0001
50.5	15,440,739	91.28%	89.34%	91.90%	0.0004	0.0000
51.5	15,322,211	91.27%	88.71%	91.43%	0.0007	0.0000
52.5	14,657,112	91.27%	88.04%	90.95%	0.0010	0.0000
53.5	14,237,890	91.22%	87.36%	90.44%	0.0015	0.0001

Account 354 Curve Fitting

[1] Age (Years)	[2] Exposures (Dollars)	[3] Observed Life Table (OLT)	[4] DEI R3-80	[5] OUCC R3-88	[6] DEI SSD	[7] OUCC SSD
54.5	13,937,978	91.08%	86.63%	89.92%	0.0020	0.0001
55.5	13,479,087	90.83%	85.88%	89.37%	0.0025	0.0002
56.5	12,989,621	90.67%	85.09%	88.79%	0.0031	0.0004
57.5	12,489,173	90.61%	84.27%	88.20%	0.0040	0.0006
58.5	12,265,644	90.61%	83.42%	87.58%	0.0052	0.0009
59.5	11,791,228	90.10%	82.52%	86.93%	0.0057	0.0010
60.5	11,504,518	90.06%	81.59%	86.26%	0.0072	0.0014
61.5	10,551,848	90.02%	80.63%	85.56%	0.0088	0.0020
62.5	10,406,448	90.01%	79.62%	84.84%	0.0108	0.0027
63.5	9,027,366	90.01%	78.57%	84.08%	0.0131	0.0035
64.5	7,498,730	90.01%	77.47%	83.30%	0.0157	0.0045
65.5	6,992,047	90.01%	76.34%	82.48%	0.0187	0.0057
66.5	6,929,088	90.01%	75.16%	81.64%	0.0221	0.0070
67.5	6,266,057	90.01%	73.93%	80.76%	0.0259	0.0086
68.5	5,898,625	90.00%	72.66%	79.85%	0.0301	0.0103
69.5	3,273,566	89.87%	71.34%	78.91%	0.0343	0.0120
70.5	3,272,700	89.85%	69.98%	77.93%	0.0395	0.0142
71.5	3,270,496	89.79%	68.56%	76.91%	0.0451	0.0166
72.5	2,838,101	89.79%	67.10%	75.86%	0.0515	0.0194
73.5	2,834,003	89.72%	65.60%	74.77%	0.0582	0.0223
74.5	2,831,403	89.64%	64.05%	73.65%	0.0655	0.0256
75.5	2,825,813	89.64%	62.45%	72.48%	0.0739	0.0294
76.5	2,825,813	89.64%	60.81%	71.28%	0.0831	0.0337
77.5	2,515,526	89.34%	59.12%	70.04%	0.0913	0.0372
78.5	2,474,913	87.90%	57.40%	68.76%	0.0930	0.0366
79.5	2,466,140	87.59%	55.63%	67.44%	0.1021	0.0406
80.5	2,465,306	87.56%	53.84%	66.08%	0.1137	0.0461
81.5	2,463,265	87.49%	52.01%	64.69%	0.1259	0.0520
82.5	1,986,030	84.05%	50.15%	63.25%	0.1149	0.0433
83.5	1,986,030	84.05%	48.27%	61.78%	0.1281	0.0496
84.5	1,980,088	83.79%	46.36%	60.28%	0.1401	0.0553
85.5			44.45%	58.73%		
Sum of Squared Differences (SSD)				[8]	1.5459	0.5989
SSD - Truncated OLT Curve				[9]	0.1556	0.0546

[1] Age in years using half-year convention
[2] Dollars exposed to retirement at the beginning of each age interval
[3] Observed life table based on the Company's property records. These numbers form the original survivor curve.
[4] The Company's selected Iowa curve to be fitted to the OLT.
[5] My selected Iowa curve to be fitted to the OLT.
[6] = ([4] - [3])^2. This is the squared difference between each point on the Company's curve and the observed survivor curve.
[7] = ([5] - [3])^2. This is the squared difference between each point on my curve and the observed survivor curve.
[8] = Sum of squared differences. The smallest SSD represents the best mathematical fit.

Account 356 Curve Fitting

[1] Age (Years)	[2] Exposures (Dollars)	[3] Observed Life Table (OLT)	[4] DEI R2-65	[5] OUCC R2-74	[6] DEI SSD	[7] OUCC SSD
0.0	572,536,129	100.00%	100.00%	100.00%	0.0000	0.0000
0.5	478,333,851	99.96%	99.93%	99.94%	0.0000	0.0000
1.5	434,825,348	99.89%	99.78%	99.80%	0.0000	0.0000
2.5	404,394,710	99.73%	99.62%	99.67%	0.0000	0.0000
3.5	379,837,891	99.33%	99.45%	99.52%	0.0000	0.0000
4.5	345,812,463	99.02%	99.27%	99.37%	0.0000	0.0000
5.5	317,776,958	98.75%	99.09%	99.21%	0.0000	0.0000
6.5	291,996,271	98.41%	98.89%	99.05%	0.0000	0.0000
7.5	274,830,043	97.98%	98.69%	98.88%	0.0001	0.0001
8.5	246,175,014	97.72%	98.47%	98.70%	0.0001	0.0001
9.5	229,924,258	97.47%	98.25%	98.51%	0.0001	0.0001
10.5	218,248,082	97.15%	98.01%	98.31%	0.0001	0.0001
11.5	212,440,216	96.93%	97.77%	98.11%	0.0001	0.0001
12.5	208,008,162	96.65%	97.51%	97.90%	0.0001	0.0002
13.5	198,137,918	96.15%	97.24%	97.67%	0.0001	0.0002
14.5	191,114,987	95.73%	96.95%	97.44%	0.0001	0.0003
15.5	177,340,239	95.51%	96.66%	97.20%	0.0001	0.0003
16.5	166,397,620	95.30%	96.35%	96.95%	0.0001	0.0003
17.5	162,679,534	95.01%	96.02%	96.69%	0.0001	0.0003
18.5	162,626,523	94.77%	95.68%	96.42%	0.0001	0.0003
19.5	158,565,244	94.46%	95.33%	96.14%	0.0001	0.0003
20.5	150,328,495	94.15%	94.96%	95.85%	0.0001	0.0003
21.5	140,516,994	93.43%	94.58%	95.55%	0.0001	0.0004
22.5	134,598,817	93.10%	94.17%	95.23%	0.0001	0.0005
23.5	129,706,378	92.23%	93.75%	94.91%	0.0002	0.0007
24.5	128,313,710	91.98%	93.32%	94.57%	0.0002	0.0007
25.5	126,539,443	91.49%	92.86%	94.21%	0.0002	0.0007
26.5	125,220,195	91.08%	92.39%	93.85%	0.0002	0.0008
27.5	120,684,755	90.69%	91.90%	93.47%	0.0001	0.0008
28.5	116,703,555	90.09%	91.39%	93.08%	0.0002	0.0009
29.5	110,340,767	89.83%	90.85%	92.67%	0.0001	0.0008
30.5	107,791,812	89.43%	90.30%	92.25%	0.0001	0.0008
31.5	105,723,709	89.15%	89.72%	91.81%	0.0000	0.0007
32.5	102,398,210	88.75%	89.13%	91.36%	0.0000	0.0007
33.5	100,288,296	88.48%	88.50%	90.89%	0.0000	0.0006
34.5	98,539,909	87.92%	87.86%	90.41%	0.0000	0.0006
35.5	97,722,561	87.72%	87.19%	89.91%	0.0000	0.0005
36.5	96,211,694	87.47%	86.50%	89.39%	0.0001	0.0004
37.5	95,526,037	87.14%	85.78%	88.86%	0.0002	0.0003
38.5	94,018,073	86.71%	85.03%	88.30%	0.0003	0.0003
39.5	90,251,186	85.96%	84.26%	87.73%	0.0003	0.0003
40.5	87,648,530	85.35%	83.45%	87.14%	0.0004	0.0003
41.5	77,148,246	84.76%	82.63%	86.53%	0.0005	0.0003
42.5	72,678,355	84.39%	81.77%	85.90%	0.0007	0.0002
43.5	70,815,285	83.76%	80.88%	85.25%	0.0008	0.0002
44.5	57,950,615	83.20%	79.96%	84.58%	0.0011	0.0002
45.5	53,987,707	82.74%	79.01%	83.89%	0.0014	0.0001
46.5	48,019,118	82.34%	78.03%	83.17%	0.0019	0.0001
47.5	45,910,304	81.24%	77.02%	82.44%	0.0018	0.0001
48.5	35,622,763	80.94%	75.97%	81.68%	0.0025	0.0001
49.5	34,985,827	80.49%	74.90%	80.90%	0.0031	0.0000
50.5	33,847,923	80.03%	73.78%	80.09%	0.0039	0.0000
51.5	31,868,740	79.38%	72.64%	79.26%	0.0045	0.0000
52.5	30,880,887	79.14%	71.46%	78.41%	0.0059	0.0001
53.5	29,900,006	78.67%	70.25%	77.53%	0.0071	0.0001

Account 356 Curve Fitting

[1] Age (Years)	[2] Exposures (Dollars)	[3] Observed Life Table (OLT)	[4] DEI R2-65	[5] OUCC R2-74	[6] DEI SSD	[7] OUCC SSD
54.5	29,454,054	78.41%	69.01%	76.63%	0.0088	0.0003
55.5	28,236,188	78.11%	67.73%	75.71%	0.0108	0.0006
56.5	26,961,052	77.57%	66.42%	74.75%	0.0124	0.0008
57.5	26,152,172	77.08%	65.07%	73.78%	0.0144	0.0011
58.5	24,697,901	76.53%	63.70%	72.77%	0.0165	0.0014
59.5	23,829,801	75.98%	62.29%	71.74%	0.0187	0.0018
60.5	22,798,189	75.64%	60.85%	70.69%	0.0219	0.0025
61.5	20,766,773	74.86%	59.38%	69.61%	0.0240	0.0028
62.5	20,206,976	74.52%	57.89%	68.50%	0.0277	0.0036
63.5	17,803,675	73.76%	56.36%	67.37%	0.0303	0.0041
64.5	16,669,799	73.14%	54.81%	66.21%	0.0336	0.0048
65.5	15,682,494	72.68%	53.23%	65.03%	0.0378	0.0059
66.5	14,284,016	68.92%	51.64%	63.82%	0.0299	0.0026
67.5	12,368,914	68.48%	50.02%	62.59%	0.0341	0.0035
68.5	11,030,380	67.79%	48.38%	61.33%	0.0377	0.0042
69.5	7,072,681	66.93%	46.73%	60.05%	0.0408	0.0047
70.5	6,586,428	66.04%	45.07%	58.75%	0.0440	0.0053
71.5	6,333,864	63.88%	43.40%	57.42%	0.0420	0.0042
72.5	3,739,428	63.11%	41.72%	56.08%	0.0458	0.0049
73.5	3,458,874	61.60%	40.03%	54.71%	0.0465	0.0047
74.5	3,413,014	61.28%	38.35%	53.33%	0.0526	0.0063
75.5	3,299,343	60.07%	36.67%	51.93%	0.0548	0.0066
76.5	3,184,158	58.46%	35.00%	50.51%	0.0550	0.0063
77.5	2,388,044	57.02%	33.34%	49.08%	0.0561	0.0063
78.5	2,342,489	55.94%	31.69%	47.64%	0.0588	0.0069
79.5	2,170,237	54.22%	30.06%	46.18%	0.0584	0.0065
80.5	2,116,548	53.50%	28.46%	44.72%	0.0627	0.0077
81.5	2,050,282	51.98%	26.87%	43.25%	0.0630	0.0076
82.5	1,589,397	50.47%	25.32%	41.77%	0.0632	0.0076
83.5	1,453,150	46.14%	23.80%	40.29%	0.0499	0.0034
84.5	1,305,432	41.45%	22.32%	38.82%	0.0366	0.0007
85.5			20.88%	37.34%		
Sum of Squared Differences (SSD)				[8]	1.2277	0.1459
SSD - Truncated OLT Curve				[9]	0.5244	0.0703

[1] Age in years using half-year convention
[2] Dollars exposed to retirement at the beginning of each age interval
[3] Observed life table based on the Company's property records. These numbers form the original survivor curve.
[4] The Company's selected Iowa curve to be fitted to the OLT.
[5] My selected Iowa curve to be fitted to the OLT.
[6] = ([4] - [3])^2. This is the squared difference between each point on the Company's curve and the observed survivor curve.
[7] = ([5] - [3])^2. This is the squared difference between each point on my curve and the observed survivor curve.
[8] = Sum of squared differences. The smallest SSD represents the best mathematical fit.

Account 365 Curve Fitting

[1] Age (Years)	[2] Exposures (Dollars)	[3] Observed Life Table (OLT)	[4] DEI R0.5-45	[5] OUCC O3-57	[6] DEI SSD	[7] OUCC SSD
0.0	989,778,112	100.00%	100.00%	100.00%	0.0000	0.0000
0.5	782,445,535	99.65%	99.58%	99.28%	0.0000	0.0000
1.5	655,607,957	97.62%	98.73%	97.83%	0.0001	0.0000
2.5	625,073,735	96.03%	97.87%	96.38%	0.0003	0.0000
3.5	588,392,453	94.68%	97.00%	94.94%	0.0005	0.0000
4.5	570,228,306	92.72%	96.13%	93.50%	0.0012	0.0001
5.5	529,170,499	90.96%	95.24%	92.06%	0.0018	0.0001
6.5	483,443,522	88.81%	94.35%	90.63%	0.0031	0.0003
7.5	446,119,351	87.14%	93.45%	89.21%	0.0040	0.0004
8.5	408,441,374	84.95%	92.53%	87.79%	0.0058	0.0008
9.5	373,106,839	82.82%	91.61%	86.38%	0.0077	0.0013
10.5	334,400,873	79.98%	90.68%	84.97%	0.0115	0.0025
11.5	320,543,614	78.22%	89.75%	83.58%	0.0133	0.0029
12.5	308,271,855	76.54%	88.80%	82.19%	0.0150	0.0032
13.5	286,572,531	75.29%	87.85%	80.81%	0.0158	0.0030
14.5	278,993,277	74.27%	86.88%	79.43%	0.0159	0.0027
15.5	256,079,374	73.39%	85.91%	78.07%	0.0157	0.0022
16.5	243,418,926	72.60%	84.93%	76.72%	0.0152	0.0017
17.5	219,028,521	71.80%	83.94%	75.38%	0.0147	0.0013
18.5	208,088,766	71.05%	82.94%	74.05%	0.0141	0.0009
19.5	197,439,596	70.31%	81.93%	72.74%	0.0135	0.0006
20.5	185,787,272	69.48%	80.91%	71.43%	0.0131	0.0004
21.5	166,188,213	68.56%	79.88%	70.15%	0.0128	0.0003
22.5	153,293,647	67.57%	78.83%	68.87%	0.0127	0.0002
23.5	150,415,835	66.67%	77.78%	67.61%	0.0123	0.0001
24.5	143,096,934	65.78%	76.71%	66.36%	0.0119	0.0000
25.5	134,995,368	64.86%	75.62%	65.13%	0.0116	0.0000
26.5	127,947,190	64.07%	74.52%	63.92%	0.0109	0.0000
27.5	119,572,299	63.09%	73.41%	62.72%	0.0107	0.0000
28.5	113,032,110	62.28%	72.28%	61.54%	0.0100	0.0001
29.5	107,147,504	61.46%	71.14%	60.38%	0.0094	0.0001
30.5	101,667,335	60.71%	69.98%	59.23%	0.0086	0.0002
31.5	95,436,458	59.97%	68.81%	58.11%	0.0078	0.0003
32.5	89,779,469	59.16%	67.62%	57.00%	0.0072	0.0005
33.5	85,198,499	58.37%	66.41%	55.91%	0.0065	0.0006
34.5	80,766,579	57.35%	65.19%	54.84%	0.0061	0.0006
35.5	77,512,880	56.46%	63.95%	53.79%	0.0056	0.0007
36.5	74,661,419	55.77%	62.70%	52.76%	0.0048	0.0009
37.5	73,060,203	55.16%	61.43%	51.75%	0.0039	0.0012
38.5	70,181,509	54.34%	60.14%	50.76%	0.0034	0.0013
39.5	66,906,650	53.63%	58.84%	49.78%	0.0027	0.0015
40.5	64,047,333	52.97%	57.53%	48.83%	0.0021	0.0017
41.5	60,662,020	52.20%	56.20%	47.90%	0.0016	0.0019
42.5	56,001,639	51.44%	54.86%	46.99%	0.0012	0.0020
43.5	52,863,914	50.65%	53.50%	46.09%	0.0008	0.0021
44.5	49,788,883	49.86%	52.14%	45.22%	0.0005	0.0022
45.5	46,796,355	49.20%	50.76%	44.36%	0.0002	0.0023

Account 365 Curve Fitting

[1] Age (Years)	[2] Exposures (Dollars)	[3] Observed Life Table (OLT)	[4] DEI R0.5-45	[5] OUCC O3-57	[6] DEI SSD	[7] OUCC SSD
46.5	43,668,387	48.61%	49.37%	43.52%	0.0001	0.0026
47.5	40,635,242	48.06%	47.97%	42.70%	0.0000	0.0029
48.5	37,866,071	47.50%	46.57%	41.90%	0.0001	0.0031
49.5	35,006,569	46.89%	45.16%	41.12%	0.0003	0.0033
50.5	32,697,480	46.40%	43.74%	40.36%	0.0007	0.0037
51.5	30,204,291	45.94%	42.32%	39.61%	0.0013	0.0040
52.5	28,370,255	45.48%	40.89%	38.88%	0.0021	0.0044
53.5	26,810,080	45.03%	39.46%	38.17%	0.0031	0.0047
54.5	25,159,235	44.58%	38.04%	37.47%	0.0043	0.0051
55.5	23,416,461	44.09%	36.61%	36.79%	0.0056	0.0053
56.5	22,114,371	43.70%	35.19%	36.12%	0.0072	0.0057
57.5	20,136,957	42.41%	33.78%	35.48%	0.0075	0.0048
58.5	17,864,917	40.12%	32.37%	34.84%	0.0060	0.0028
59.5	16,540,649	38.41%	30.97%	34.22%	0.0055	0.0018
60.5	15,949,273	37.21%	29.57%	33.62%	0.0058	0.0013
61.5	15,049,000	36.19%	28.20%	33.03%	0.0064	0.0010
62.5	14,175,404	34.53%	26.83%	32.45%	0.0059	0.0004
63.5	12,941,789	32.57%	25.48%	31.89%	0.0050	0.0000
64.5	11,616,826	29.80%	24.15%	31.33%	0.0032	0.0002
65.5	10,261,557	27.53%	22.84%	30.80%	0.0022	0.0011
66.5	8,584,543	23.96%	21.55%	30.27%	0.0006	0.0040
67.5	7,853,129	22.48%	20.28%	29.76%	0.0005	0.0053
68.5	7,172,848	21.26%	19.04%	29.25%	0.0005	0.0064
69.5	5,890,478	17.66%	17.82%	28.76%	0.0000	0.0123
70.5	5,842,654	17.52%	16.63%	28.28%	0.0001	0.0116
71.5	4,853,750	14.55%	15.47%	27.81%	0.0001	0.0176
72.5	2,966,555	14.34%	14.34%	27.35%	0.0000	0.0169
73.5	2,947,591	14.25%	13.24%	26.90%	0.0001	0.0160
74.5	2,922,079	14.13%	12.18%	26.46%	0.0004	0.0152
75.5	2,888,736	13.97%	11.15%	26.03%	0.0008	0.0146
76.5	2,846,737	13.77%	10.16%	25.61%	0.0013	0.0140
77.5	1,983,507	13.59%	9.20%	25.20%	0.0019	0.0135
78.5	1,974,593	13.53%	8.28%	24.80%	0.0028	0.0127
79.5	1,950,032	13.36%	7.40%	24.40%	0.0036	0.0122
80.5	1,932,466	13.24%	6.55%	24.01%	0.0045	0.0116
81.5	1,911,482	13.10%	5.74%	23.64%	0.0054	0.0111
82.5	1,288,731	12.96%	4.96%	23.26%	0.0064	0.0106
83.5	1,279,319	12.87%	4.21%	22.90%	0.0075	0.0101
84.5	830,349	8.35%	3.50%	22.54%	0.0024	0.0201
85.5			2.80%	22.19%		

Sum of Squared Differences (SSD)	[8]	0.4587	0.3390
SSD - Truncated OLT Curve	[9]	0.4200	0.1032

Account 365 Curve Fitting

[1]	[2]	[3]	[4]	[5]	[6]	[7]
Age (Years)	**Exposures (Dollars)**	**Observed Life Table (OLT)**	**DEI R0.5-45**	**OUCC O3-57**	**DEI SSD**	**OUCC SSD**

[1] Age in years using half-year convention

[2] Dollars exposed to retirement at the beginning of each age interval

[3] Observed life table based on the Company's property records. These numbers form the original survivor curve.

[4] The Company's selected Iowa curve to be fitted to the OLT.

[5] My selected Iowa curve to be fitted to the OLT.

[6] = ([4] - [3])^2. This is the squared difference between each point on the Company's curve and the observed survivor curve.

[7] = ([5] - [3])^2. This is the squared difference between each point on my curve and the observed survivor curve.

[8] = Sum of squared differences. The smallest SSD represents the best mathematical fit.

Account 367 Curve Fitting

[1] Age (Years)	[2] Exposures (Dollars)	[3] Observed Life Table (OLT)	[4] DEI R2-60	[5] OUCC R1.5-68	[6] DEI SSD	[7] OUCC SSD
0.0	814,830,490	100.00%	100.00%	100.00%	0.0000	0.0000
0.5	650,312,062	99.95%	99.92%	99.87%	0.0000	0.0000
1.5	563,798,466	99.68%	99.76%	99.61%	0.0000	0.0000
2.5	541,873,470	99.36%	99.58%	99.33%	0.0000	0.0000
3.5	504,858,266	99.05%	99.40%	99.05%	0.0000	0.0000
4.5	497,461,800	98.66%	99.20%	98.77%	0.0000	0.0000
5.5	468,218,615	98.34%	99.00%	98.47%	0.0000	0.0000
6.5	448,083,023	97.94%	98.78%	98.17%	0.0001	0.0000
7.5	430,075,568	97.60%	98.56%	97.86%	0.0001	0.0000
8.5	418,344,034	97.21%	98.32%	97.53%	0.0001	0.0000
9.5	407,080,981	96.70%	98.06%	97.21%	0.0002	0.0000
10.5	392,911,120	96.35%	97.80%	96.87%	0.0002	0.0000
11.5	385,039,674	96.02%	97.52%	96.52%	0.0002	0.0000
12.5	376,777,476	95.73%	97.22%	96.16%	0.0002	0.0000
13.5	357,009,408	95.48%	96.92%	95.80%	0.0002	0.0000
14.5	342,291,345	95.25%	96.59%	95.42%	0.0002	0.0000
15.5	311,665,065	95.02%	96.25%	95.04%	0.0002	0.0000
16.5	296,863,648	94.76%	95.90%	94.65%	0.0001	0.0000
17.5	280,502,424	94.55%	95.52%	94.24%	0.0001	0.0000
18.5	264,069,348	94.31%	95.13%	93.83%	0.0001	0.0000
19.5	253,716,279	94.05%	94.72%	93.40%	0.0000	0.0000
20.5	243,472,079	93.76%	94.29%	92.97%	0.0000	0.0001
21.5	224,746,212	93.49%	93.84%	92.52%	0.0000	0.0001
22.5	205,933,417	93.24%	93.37%	92.06%	0.0000	0.0001
23.5	191,994,345	92.92%	92.88%	91.60%	0.0000	0.0002
24.5	177,512,144	92.58%	92.37%	91.12%	0.0000	0.0002
25.5	159,240,877	92.26%	91.84%	90.62%	0.0000	0.0003
26.5	142,779,042	91.87%	91.28%	90.12%	0.0000	0.0003
27.5	124,318,670	91.50%	90.69%	89.60%	0.0001	0.0004
28.5	108,853,868	91.12%	90.09%	89.07%	0.0001	0.0004
29.5	96,580,967	90.77%	89.45%	88.53%	0.0002	0.0005
30.5	86,955,023	90.31%	88.79%	87.97%	0.0002	0.0005
31.5	78,807,126	89.86%	88.10%	87.39%	0.0003	0.0006
32.5	68,663,104	89.44%	87.39%	86.81%	0.0004	0.0007
33.5	61,240,891	88.99%	86.64%	86.20%	0.0006	0.0008
34.5	53,482,095	88.45%	85.87%	85.58%	0.0007	0.0008
35.5	47,811,635	87.92%	85.06%	84.95%	0.0008	0.0009
36.5	43,478,355	87.33%	84.22%	84.30%	0.0010	0.0009
37.5	40,499,449	86.67%	83.35%	83.63%	0.0011	0.0009
38.5	37,414,075	85.98%	82.45%	82.94%	0.0012	0.0009
39.5	34,217,988	85.18%	81.51%	82.24%	0.0013	0.0009
40.5	31,464,225	84.33%	80.54%	81.51%	0.0014	0.0008
41.5	27,636,203	83.47%	79.53%	80.77%	0.0016	0.0007
42.5	23,310,860	82.57%	78.48%	80.01%	0.0017	0.0007
43.5	19,464,022	81.53%	77.40%	79.23%	0.0017	0.0005
44.5	15,639,232	80.49%	76.28%	78.43%	0.0018	0.0004
45.5	12,100,403	79.41%	75.12%	77.61%	0.0018	0.0003

Account 367 Curve Fitting

[1]	[2]	[3]	[4]	[5]	[6]	[7]
Age (Years)	**Exposures (Dollars)**	**Observed Life Table (OLT)**	**DEI R2-60**	**OUCC R1.5-68**	**DEI SSD**	**OUCC SSD**
46.5	9,793,225	78.23%	73.92%	76.76%	0.0019	0.0002
47.5	7,530,483	77.04%	72.69%	75.90%	0.0019	0.0001
48.5	5,619,595	71.70%	71.41%	75.02%	0.0000	0.0011
49.5	3,646,438	57.79%	70.10%	74.11%	0.0151	0.0266
50.5	1,983,269	41.98%	68.74%	73.18%	0.0716	0.0974
51.5	1,289,139	33.72%	67.35%	72.23%	0.1131	0.1483
52.5	990,822	29.26%	65.92%	71.26%	0.1344	0.1764
53.5	800,804	26.26%	64.45%	70.27%	0.1458	0.1937
54.5	376,426	14.35%	62.94%	69.25%	0.2361	0.3014
55.5	282,785	11.46%	61.39%	68.21%	0.2493	0.3221
56.5	268,954	10.96%	59.81%	67.15%	0.2387	0.3158
57.5	202,900	10.65%	58.20%	66.07%	0.2261	0.3071
58.5	154,787	10.43%	56.55%	64.97%	0.2127	0.2974
59.5	113,158	10.15%	54.87%	63.84%	0.2000	0.2883
60.5	65,995	9.88%	53.17%	62.69%	0.1874	0.2789
61.5	45,860	9.68%	51.43%	61.52%	0.1743	0.2688
62.5	44,155	9.44%	49.68%	60.34%	0.1619	0.2590
63.5	41,235	8.94%	47.90%	59.13%	0.1518	0.2519
64.5	39,536	8.24%	46.11%	57.90%	0.1434	0.2466
65.5	20,276	8.05%	44.30%	56.65%	0.1314	0.2362
66.5	14,266	7.96%	42.49%	55.39%	0.1192	0.2249
67.5	12,599	7.85%	40.66%	54.11%	0.1077	0.2140
68.5	10,406	7.77%	38.84%	52.81%	0.0965	0.2029
69.5	9,567	7.56%	37.02%	51.50%	0.0868	0.1931
70.5	9,441	7.46%	35.21%	50.17%	0.0770	0.1824
71.5	9,391	7.42%	33.41%	48.83%	0.0675	0.1715
72.5	4,690	7.35%	31.62%	47.49%	0.0589	0.1611
73.5	4,689	7.35%	29.86%	46.13%	0.0507	0.1504
74.5	4,689	7.35%	28.12%	44.76%	0.0432	0.1400
75.5	4,689	7.35%	26.42%	43.39%	0.0364	0.1299
76.5	7,449	7.35%	24.75%	42.02%	0.0303	0.1202
77.5	5,423	7.11%	23.12%	40.64%	0.0256	0.1124
78.5	5,387	7.06%	21.53%	39.26%	0.0209	0.1037
79.5	5,312	6.97%	20.00%	37.88%	0.0170	0.0956
80.5	5,200	6.82%	18.51%	36.51%	0.0137	0.0882
81.5	4,747	6.22%	17.07%	35.14%	0.0118	0.0837
82.5	3,930	6.22%	15.70%	33.78%	0.0090	0.0760
83.5	3,930	6.22%	14.38%	32.43%	0.0067	0.0687
84.5	3,930	6.22%	13.12%	31.09%	0.0048	0.0619
85.5	2,344	6.22%	11.93%	29.77%	0.0033	0.0555
86.5	2,344	6.22%	10.80%	28.46%	0.0021	0.0495
87.5	2,344	6.22%	9.73%	27.17%	0.0012	0.0439
88.5	2,344	6.22%	8.72%	25.90%	0.0006	0.0387
89.5	2,292	6.08%	7.78%	24.65%	0.0003	0.0345
90.5	1,615	4.29%	6.90%	23.43%	0.0007	0.0366
91.5	1,563	4.15%	6.08%	22.23%	0.0004	0.0327
92.5	1,224	3.25%	5.32%	21.05%	0.0004	0.0317

Account 367 Curve Fitting

[1]	[2]	[3]	[4]	[5]	[6]	[7]
Age (Years)	**Exposures (Dollars)**	**Observed Life Table (OLT)**	**DEI R2-60**	**OUCC R1.5-68**	**DEI SSD**	**OUCC SSD**
93.5	859	2.28%	4.62%	19.91%	0.0005	0.0311
94.5	755	2.00%	3.98%	18.79%	0.0004	0.0282
95.5	755	2.00%	3.39%	17.70%	0.0002	0.0247
96.5	755	2.00%	2.86%	16.65%	0.0001	0.0215
97.5	729	1.94%	2.38%	15.63%	0.0000	0.0187
98.5			1.95%	14.64%		
Sum of Squared Differences (SSD)				[8]	3.7110	7.0591
SSD - Truncated OLT Curve				[9]	0.0202	0.0142

[1] Age in years using half-year convention

[2] Dollars exposed to retirement at the beginning of each age interval

[3] Observed life table based on the Company's property records. These numbers form the original survivor curve.

[4] The Company's selected Iowa curve to be fitted to the OLT.

[5] My selected Iowa curve to be fitted to the OLT.

[6] = ([4] - [3])^2. This is the squared difference between each point on the Company's curve and the observed survivor curve.

[7] = ([5] - [3])^2. This is the squared difference between each point on my curve and the observed survivor curve.

[8] = Sum of squared differences. The smallest SSD represents the best mathematical fit.

Duke Energy Indiana
Electric Division
354.00 Towers and Fixtures

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of June 30, 2023
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 88 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1937	1,980,088.29	88.00	22,501.00	18.71	421,068.44
1940	380,311.52	88.00	4,321.72	20.24	87,466.13
1945	300,948.55	88.00	3,419.87	22.99	78,609.38
1947	5,589.74	88.00	63.52	24.16	1,534.75
1949	1,980.02	88.00	22.50	25.37	570.88
1950	432,394.15	88.00	4,913.57	25.99	127,710.73
1953	2,617,040.94	88.00	29,739.10	27.90	829,816.63
1954	366,411.25	88.00	4,163.76	28.56	118,931.83
1955	663,031.06	88.00	7,534.44	29.23	220,214.42
1956	62,958.47	88.00	715.44	29.90	21,391.60
1957	506,683.28	88.00	5,757.76	30.58	176,074.81
1958	1,528,636.03	88.00	17,370.86	31.27	543,163.20
1959	1,379,081.75	88.00	15,671.38	31.96	500,928.87
1960	144,242.42	88.00	1,639.12	32.67	53,546.76
1961	947,079.80	88.00	10,762.27	33.38	359,282.61
1962	282,332.69	88.00	3,208.33	34.10	109,412.21
1963	405,544.33	88.00	4,608.46	34.83	160,506.57
1964	223,186.07	88.00	2,536.21	35.56	90,191.84
1965	491,652.86	88.00	5,586.96	36.30	202,815.57
1966	466,521.79	88.00	5,301.38	37.05	196,406.23
1967	419,263.32	88.00	4,764.36	37.80	180,098.47
1968	278,213.34	88.00	3,161.52	38.56	121,910.64
1969	412,350.29	88.00	4,685.80	39.33	184,299.65
1970	665,099.16	88.00	7,557.95	40.10	303,108.59
1971	115,521.32	88.00	1,312.74	40.88	53,670.01
1972	794,770.72	88.00	9,031.49	41.67	376,335.04
1973	13,965.75	88.00	158.70	42.46	6,738.57

Duke Energy Indiana
Electric Division
354.00 Towers and Fixtures

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of June 30, 2023
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 88 **Survivor Curve:** R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1974	8,168,996.25	88.00	92,829.50	43.26	4,015,606.70
1975	989,940.88	88.00	11,249.33	44.06	495,656.94
1976	6,844,959.43	88.00	77,783.63	44.87	3,490,451.04
1977	2,187,774.46	88.00	24,861.07	45.69	1,135,884.38
1978	15,390,760.76	88.00	174,895.01	46.51	8,134,424.22
1979	170,679.28	88.00	1,939.54	47.34	91,811.77
1980	1,839,370.92	88.00	20,901.94	48.17	1,006,827.09
1981	12,731,423.41	88.00	144,675.27	49.01	7,090,046.43
1982	96,532.97	88.00	1,096.97	49.85	54,683.26
1983	71,302.35	88.00	810.25	50.70	41,080.64
1984	45,758.44	88.00	519.98	51.56	26,807.73
1985	116,818.68	88.00	1,327.49	52.41	69,579.29
1986	1,125,390.87	88.00	12,788.53	53.28	681,356.66
1987	48,554.06	88.00	551.75	54.15	29,876.23
1988	66,965.39	88.00	760.97	55.02	41,870.36
1989	72,340.43	88.00	822.05	55.90	45,953.80
1990	266,491.58	88.00	3,028.31	56.79	171,971.15
1991	158,665.21	88.00	1,803.01	57.68	103,992.21
1996	831,730.26	88.00	9,451.48	62.19	587,778.47
1999	372,793.33	88.00	4,236.29	64.95	275,142.52
2007	496,842.78	88.00	5,645.94	72.46	409,132.59
2008	5,424.02	88.00	61.64	73.42	4,525.27
2009	4,094.82	88.00	46.53	74.37	3,460.82
2011	16,902,876.78	88.00	192,078.15	76.30	14,654,728.11
2012	1,934,935.64	88.00	21,987.91	77.26	1,698,779.43
2013	376,219.21	88.00	4,275.22	78.23	334,439.38
2016	343.69	88.00	3.91	81.14	316.90

Duke Energy Indiana
Electric Division
354.00 Towers and Fixtures

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of June 30, 2023
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 88 **Survivor Curve:** R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2017	3,152.94	88.00	35.83	82.11	2,942.09
2018	6,723.24	88.00	76.40	83.09	6,348.24
2019	216,100.72	88.00	2,455.69	84.07	206,449.81
2020	206,987.57	88.00	2,352.13	85.05	200,050.65
2021	934,737.37	88.00	10,622.02	86.03	913,838.13
2022	663,025.85	88.00	7,534.38	87.02	655,608.67
2023	22,984.25	88.00	261.18	87.75	22,919.96
Total	89,256,596.75	88.00	1,014,279.52	51.49	52,230,145.38

Composite Average Remaining Life ... *51.49 Years*

Duke Energy Indiana
Electric Division
356.00 Overhead Conductors and Devices

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of June 30, 2023
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 74 *Survivor Curve:* R2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1937	1,309,548.55	74.00	17,696.57	15.33	271,284.44
1940	392,884.72	74.00	5,309.24	16.51	87,668.04
1941	6,244.32	74.00	84.38	16.92	1,427.85
1942	24,808.38	74.00	335.25	17.34	5,812.46
1943	99,944.15	74.00	1,350.59	17.76	23,989.01
1944	628.74	74.00	8.50	18.19	154.58
1945	708,115.51	74.00	9,569.11	18.63	178,307.13
1946	26,994.66	74.00	364.79	19.08	6,960.59
1947	45,951.78	74.00	620.97	19.54	12,131.19
1948	28,031.27	74.00	378.80	20.00	7,576.17
1949	190,742.50	74.00	2,577.60	20.47	52,767.61
1950	2,491,791.70	74.00	33,672.80	20.95	705,457.84
1951	37,033.46	74.00	500.45	21.44	10,729.40
1952	390,951.28	74.00	5,283.12	21.93	115,883.30
1953	3,794,111.47	74.00	51,271.69	22.44	1,150,401.52
1954	1,206,290.84	74.00	16,301.20	22.95	374,128.87
1955	1,813,712.08	74.00	24,509.58	23.47	575,244.62
1956	581,796.14	74.00	7,862.10	24.00	188,665.07
1957	875,852.43	74.00	11,835.82	24.53	290,389.50
1958	977,709.42	74.00	13,212.27	25.08	331,334.00
1959	2,184,859.34	74.00	29,525.07	25.63	756,746.78
1960	453,267.46	74.00	6,125.23	26.19	160,418.72
1961	1,786,905.76	74.00	24,147.33	26.76	646,090.43
1962	920,803.23	74.00	12,443.27	27.33	340,107.55
1963	671,222.51	74.00	9,070.56	27.91	253,203.86
1964	1,262,019.36	74.00	17,054.29	28.50	486,116.99
1965	633,092.24	74.00	8,555.29	29.10	248,989.44

Duke Energy Indiana
Electric Division
356.00 Overhead Conductors and Devices

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of June 30, 2023
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: *74* *Survivor Curve:* *R2*

Year *(1)*	*Original Cost* *(2)*	*Avg. Service Life* *(3)*	*Avg. Annual Accrual* *(4)*	*Avg. Remaining Life* *(5)*	*Future Annual Accruals* *(6)*
1966	1,076,428.88	74.00	14,546.31	29.71	432,146.03
1967	1,094,616.49	74.00	14,792.09	30.32	448,491.93
1968	344,569.81	74.00	4,656.34	30.94	144,074.29
1969	790,512.80	74.00	10,682.59	31.57	337,228.16
1970	886,163.32	74.00	11,975.16	32.20	385,612.06
1971	1,695,346.77	74.00	22,910.05	32.84	752,466.94
1972	923,238.26	74.00	12,476.17	33.49	417,851.51
1973	406,573.31	74.00	5,494.22	34.15	187,604.59
1974	10,066,219.29	74.00	136,029.75	34.81	4,735,196.92
1975	1,447,855.87	74.00	19,565.59	35.48	694,145.82
1976	5,678,916.01	74.00	76,741.97	36.15	2,774,361.33
1977	3,621,821.62	74.00	48,943.45	36.84	1,802,885.12
1978	12,362,930.25	74.00	167,066.33	37.52	6,268,923.73
1979	1,304,807.37	74.00	17,632.50	38.22	673,907.04
1980	4,096,926.65	74.00	55,363.78	38.92	2,154,774.34
1981	9,815,426.79	74.00	132,640.67	39.63	5,256,101.92
1982	1,934,840.58	74.00	26,146.45	40.34	1,054,785.90
1983	2,937,172.38	74.00	39,691.45	41.06	1,629,751.10
1984	1,032,665.70	74.00	13,954.92	41.78	583,105.61
1985	323,681.52	74.00	4,374.07	42.52	185,976.03
1986	1,194,875.05	74.00	16,146.93	43.25	698,428.63
1987	602,259.15	74.00	8,138.62	44.00	358,070.62
1988	1,104,594.22	74.00	14,926.92	44.75	667,931.32
1989	1,803,675.30	74.00	24,373.95	45.50	1,109,024.94
1990	2,848,624.64	74.00	38,494.86	46.26	1,780,737.51
1991	1,723,160.02	74.00	23,285.91	47.03	1,095,044.79
1992	2,058,422.66	74.00	27,816.47	47.80	1,329,518.43

Duke Energy Indiana
Electric Division
356.00 Overhead Conductors and Devices
Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of June 30, 2023
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 74 *Survivor Curve:* R2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1993	5,982,143.28	74.00	80,839.63	48.57	3,926,453.57
1994	3,130,926.08	74.00	42,309.74	49.35	2,088,151.84
1995	3,988,475.89	74.00	53,898.23	50.14	2,702,437.81
1996	737,704.70	74.00	9,968.97	50.93	507,740.24
1997	1,207,518.95	74.00	16,317.80	51.73	844,093.64
1998	1,250,341.78	74.00	16,896.48	52.53	887,559.18
1999	3,603,327.91	74.00	48,693.54	53.34	2,597,154.39
2000	5,404,075.71	74.00	73,027.92	54.15	3,954,298.06
2001	8,641,398.68	74.00	116,775.45	54.96	6,418,342.66
2002	7,703,717.12	74.00	104,104.10	55.79	5,807,454.53
2003	3,478,710.87	74.00	47,009.52	56.61	2,661,219.13
2004	3,432,647.33	74.00	46,387.05	57.44	2,664,449.88
2005	3,199,039.23	74.00	43,230.18	58.28	2,519,254.00
2006	10,528,959.93	74.00	142,282.99	59.11	8,410,922.85
2007	14,449,905.52	74.00	195,268.65	59.96	11,707,672.24
2008	6,148,815.40	74.00	83,091.96	60.81	5,052,475.86
2009	8,797,264.36	74.00	118,881.74	61.66	7,329,952.26
2010	3,900,615.93	74.00	52,710.93	62.51	3,295,120.86
2011	5,319,419.47	74.00	71,883.92	63.37	4,555,629.06
2012	12,284,648.08	74.00	166,008.47	64.24	10,664,200.29
2013	15,622,610.78	74.00	211,115.99	65.11	13,745,055.35
2014	28,290,799.50	74.00	382,307.43	65.98	25,224,836.68
2015	17,315,779.23	74.00	233,996.61	66.86	15,644,176.88
2016	25,678,020.76	74.00	346,999.68	67.74	23,504,838.03
2017	32,623,862.70	74.00	440,862.24	68.62	30,252,467.77
2018	34,132,122.50	74.00	461,244.09	69.51	32,060,294.92
2019	26,313,187.54	74.00	355,583.00	70.40	25,033,162.65

Duke Energy Indiana
Electric Division
356.00 Overhead Conductors and Devices

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of June 30, 2023
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 74 *Survivor Curve:* R2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2020	36,308,548.84	74.00	490,655.21	71.29	34,981,242.85
2021	43,104,562.57	74.00	582,493.07	72.19	42,051,784.12
2022	79,507,092.18	74.00	1,074,418.29	73.10	78,534,923.47
2023	20,746,519.28	74.00	280,357.88	73.77	20,683,068.21
Total	568,924,400.11	74.00	7,688,154.16	61.85	475,550,566.80

Composite Average Remaining Life ... 61.85 Years

Duke Energy Indiana
Electric Division
365.00 Overhead Conductors and Devices

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of June 30, 2023
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 57 *Survivor Curve:* O3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1925	12.73	56.21	0.23	50.70	11.48
1937	1,206,936.23	56.21	21,471.86	53.18	1,141,864.14
1940	595,364.30	56.21	10,591.76	53.67	568,456.62
1944	1.73	56.21	0.03	54.24	1.67
1945	817,010.00	56.21	14,534.92	54.36	790,118.86
1950	3,363,045.41	56.21	59,829.87	54.89	3,284,163.94
1953	596,115.23	56.21	10,605.12	55.13	584,711.80
1954	910,474.61	56.21	16,197.69	55.20	894,141.88
1955	797,468.94	56.21	14,187.28	55.26	784,027.70
1956	1,104,364.62	56.21	19,647.07	55.32	1,086,892.56
1957	1,276,056.52	56.21	22,701.54	55.37	1,256,942.92
1958	1,155,668.07	56.21	20,559.78	55.41	1,139,209.90
1959	1,047,119.37	56.21	18,628.66	55.45	1,032,871.59
1960	1,042,655.36	56.21	18,549.24	55.48	1,029,087.66
1961	1,196,634.92	56.21	21,288.60	55.50	1,181,543.31
1962	1,146,111.91	56.21	20,389.77	55.52	1,132,004.33
1963	1,079,397.89	56.21	19,202.90	55.53	1,066,334.14
1964	1,177,284.55	56.21	20,944.34	55.54	1,163,245.18
1965	1,318,693.36	56.21	23,460.06	55.54	1,302,950.97
1966	1,086,199.81	56.21	19,323.91	55.53	1,073,122.33
1967	1,468,039.78	56.21	26,116.99	55.52	1,450,089.50
1968	1,402,058.72	56.21	24,943.16	55.51	1,384,536.18
1969	1,328,586.00	56.21	23,636.06	55.49	1,311,565.27
1970	1,631,378.05	56.21	29,022.84	55.46	1,609,728.53
1971	2,517,139.26	56.21	44,780.88	55.43	2,482,398.76
1972	2,062,796.98	56.21	36,697.95	55.40	2,033,093.62
1973	2,488,151.04	56.21	44,265.16	55.37	2,450,774.82

Duke Energy Indiana
Electric Division
365.00 Overhead Conductors and Devices

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of June 30, 2023
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 57 *Survivor Curve:* O3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1974	2,432,530.49	56.21	43,275.65	55.32	2,394,157.71
1975	2,665,537.01	56.21	47,420.93	55.28	2,621,342.14
1976	2,703,051.93	56.21	48,088.33	55.23	2,655,930.76
1977	2,486,300.70	56.21	44,232.25	55.18	2,440,834.96
1978	2,431,235.59	56.21	43,252.62	55.13	2,384,434.35
1979	2,668,523.51	56.21	47,474.06	55.07	2,614,505.83
1980	3,994,913.76	56.21	71,071.05	55.02	3,909,991.11
1981	2,730,073.89	56.21	48,569.06	54.96	2,669,333.96
1982	2,372,816.49	56.21	42,213.32	54.90	2,317,477.93
1983	2,725,096.67	56.21	48,480.52	54.84	2,658,613.13
1984	2,382,755.08	56.21	42,390.13	54.78	2,322,075.37
1985	1,471,789.44	56.21	26,183.70	54.72	1,432,812.06
1986	2,557,533.92	56.21	45,499.51	54.66	2,487,071.67
1987	2,702,628.65	56.21	48,080.80	54.60	2,625,360.63
1988	3,856,364.00	56.21	68,606.20	54.55	3,742,242.90
1989	4,143,069.28	56.21	73,706.80	54.49	4,016,643.01
1990	5,386,352.70	56.21	95,825.29	54.44	5,216,937.67
1991	5,926,647.72	56.21	105,437.34	54.39	5,735,034.28
1992	4,670,790.02	56.21	83,095.15	54.35	4,515,989.79
1993	4,937,425.24	56.21	87,838.69	54.31	4,770,314.58
1994	5,440,132.48	56.21	96,782.05	54.27	5,252,294.78
1995	6,752,815.72	56.21	120,135.19	54.24	6,515,643.87
1996	5,864,522.62	56.21	104,332.11	54.21	5,655,624.06
1997	6,605,624.96	56.21	117,516.61	54.19	6,367,903.02
1998	6,211,132.81	56.21	110,498.44	54.17	5,985,667.14
1999	1,735,566.89	56.21	30,876.40	54.16	1,672,222.09
2000	11,905,415.50	56.21	211,801.92	54.15	11,469,950.40

Duke Energy Indiana
Electric Division
365.00 Overhead Conductors and Devices

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of June 30, 2023
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 57 *Survivor Curve:* O3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2001	19,029,920.61	56.21	338,549.61	54.16	18,335,203.79
2002	10,637,109.38	56.21	189,238.27	54.17	10,250,433.34
2003	9,576,262.92	56.21	170,365.40	54.18	9,230,917.24
2004	13,893,384.25	56.21	247,168.65	54.21	13,398,262.65
2005	23,452,921.90	56.21	417,236.50	54.24	22,630,878.31
2006	12,657,735.20	56.21	225,185.98	54.28	12,222,856.10
2007	23,911,110.37	56.21	425,387.85	54.33	23,109,694.21
2008	6,062,464.63	56.21	107,853.58	54.38	5,865,260.55
2009	18,072,374.06	56.21	321,514.49	54.45	17,505,347.73
2010	5,802,579.35	56.21	103,230.12	54.52	5,627,928.28
2011	17,638,381.35	56.21	313,793.59	54.60	17,132,671.51
2012	32,253,920.14	56.21	573,809.64	54.69	31,380,127.32
2013	31,072,851.94	56.21	552,797.99	54.79	30,285,236.55
2014	33,486,116.62	56.21	595,730.89	54.89	32,700,105.41
2015	38,703,240.04	56.21	688,545.53	55.00	37,873,175.44
2016	41,096,359.97	56.21	731,120.05	55.13	40,304,396.61
2017	43,791,924.06	56.21	779,075.17	55.26	43,050,193.31
2018	18,160,478.50	56.21	323,081.90	55.40	17,897,664.94
2019	54,326,036.54	56.21	966,481.08	55.54	53,681,724.49
2020	46,773,282.47	56.21	832,114.68	55.70	46,347,431.65
2021	137,412,165.05	56.21	2,444,615.26	55.86	136,560,029.76
2022	141,077,413.66	56.21	2,509,821.45	56.03	140,630,297.37
2023	31,251,382.54	56.21	555,974.11	56.16	31,226,173.14
Total	953,714,828.01	56.21	16,966,953.58	55.22	936,930,308.57

Composite Average Remaining Life ... 55.22 Years

Duke Energy Indiana
Electric Division
367.00 Underground Conductors and Devices

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of June 30, 2023
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 68 *Survivor Curve:* R1.5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1924	703.22	68.00	10.34	10.51	108.73
1937	1,585.18	68.00	23.31	14.60	340.31
1940	816.38	68.00	12.01	15.66	187.96
1945	1,787.43	68.00	26.29	17.54	461.17
1950	4,610.72	68.00	67.80	19.61	1,329.54
1953	553.07	68.00	8.13	20.94	170.28
1954	2,068.60	68.00	30.42	21.39	650.83
1955	1,461.74	68.00	21.50	21.86	469.90
1956	5,744.53	68.00	84.48	22.33	1,886.59
1957	17,260.00	68.00	253.82	22.81	5,790.85
1958	622.43	68.00	9.15	23.30	213.29
1959	599.73	68.00	8.82	23.80	209.91
1960	572.05	68.00	8.41	24.30	204.45
1961	1,183.92	68.00	17.41	24.82	432.07
1962	42,246.75	68.00	621.27	25.34	15,740.01
1963	35,937.75	68.00	528.49	25.86	13,668.63
1964	42,560.82	68.00	625.89	26.40	16,521.73
1965	104,656.56	68.00	1,539.05	26.94	41,462.76
1966	169,884.28	68.00	2,498.27	27.49	68,675.50
1967	162,467.71	68.00	2,389.21	28.05	67,010.19
1968	287,972.77	68.00	4,234.85	28.61	121,161.17
1969	399,135.02	68.00	5,869.57	29.18	171,290.03
1970	362,727.01	68.00	5,334.17	29.76	158,747.87
1971	575,417.86	68.00	8,461.94	30.35	256,793.03
1972	979,639.20	68.00	14,406.32	30.94	445,713.90
1973	1,504,353.58	68.00	22,122.63	31.54	697,674.53
1974	1,731,783.84	68.00	25,467.16	32.14	818,628.43

Duke Energy Indiana
Electric Division
367.00 Underground Conductors and Devices

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of June 30, 2023
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 68 **Survivor Curve:** R1.5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1975	2,071,430.49	68.00	30,461.91	32.76	997,808.42
1976	2,090,049.37	68.00	30,735.72	33.38	1,025,860.15
1977	3,285,993.50	68.00	48,322.96	34.00	1,643,049.85
1978	3,510,642.66	68.00	51,626.59	34.63	1,788,086.35
1979	3,344,047.61	68.00	49,176.69	35.27	1,734,578.18
1980	3,977,291.48	68.00	58,489.00	35.92	2,100,818.66
1981	3,469,301.90	68.00	51,018.64	36.57	1,865,644.25
1982	2,374,976.32	68.00	34,925.78	37.23	1,300,130.41
1983	2,839,957.87	68.00	41,763.68	37.89	1,582,305.19
1984	2,710,637.67	68.00	39,861.93	38.56	1,536,921.25
1985	2,598,273.37	68.00	38,209.53	39.23	1,498,926.90
1986	4,010,115.02	68.00	58,971.70	39.91	2,353,504.75
1987	5,341,823.15	68.00	78,555.45	40.59	3,188,803.61
1988	7,366,028.10	68.00	108,322.88	41.28	4,471,935.96
1989	7,095,689.19	68.00	104,347.34	41.98	4,380,276.44
1990	9,769,819.22	68.00	143,672.40	42.68	6,131,437.15
1991	7,684,221.58	68.00	113,002.15	43.38	4,902,333.63
1992	9,346,029.91	68.00	137,440.26	44.09	6,059,893.21
1993	12,037,648.92	68.00	177,022.51	44.81	7,931,755.81
1994	15,211,165.18	68.00	223,691.40	45.52	10,183,377.40
1995	18,046,297.44	68.00	265,384.11	46.25	12,273,577.71
1996	15,946,396.79	68.00	234,503.53	46.97	11,015,780.98
1997	17,784,977.75	68.00	261,541.22	47.71	12,477,437.73
1998	13,877,410.18	68.00	204,077.55	48.44	9,885,976.28
1999	13,313,489.36	68.00	195,784.68	49.18	9,629,196.01
2000	18,070,525.30	68.00	265,740.40	49.93	13,267,199.52
2001	18,035,859.74	68.00	265,230.62	50.67	13,440,100.00

Duke Energy Indiana
Electric Division
367.00 Underground Conductors and Devices

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of June 30, 2023
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: **68** *Survivor Curve:* **R1.5**

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2002	9,680,843.53	68.00	142,363.94	51.42	7,320,874.64
2003	10,147,845.38	68.00	149,231.55	52.18	7,786,709.20
2004	16,160,875.93	68.00	237,657.60	52.94	12,580,734.43
2005	15,934,173.89	68.00	234,323.78	53.70	12,582,821.36
2006	13,900,493.49	68.00	204,417.01	54.46	11,133,215.86
2007	29,875,896.85	68.00	439,347.10	55.23	24,265,582.78
2008	13,709,248.94	68.00	201,604.62	56.00	11,290,704.37
2009	18,761,939.58	68.00	275,908.16	56.78	15,665,797.67
2010	6,855,745.67	68.00	100,818.80	57.56	5,803,038.52
2011	6,275,640.64	68.00	92,287.92	58.34	5,384,167.44
2012	12,440,086.76	68.00	182,940.65	59.13	10,816,891.04
2013	9,148,323.50	68.00	134,532.84	59.92	8,060,772.00
2014	9,794,574.11	68.00	144,036.44	60.71	8,744,518.10
2015	16,045,968.72	68.00	235,967.81	61.51	14,513,507.74
2016	16,528,353.12	68.00	243,061.62	62.31	15,144,387.65
2017	25,353,547.22	68.00	372,842.61	63.11	23,529,929.67
2018	22,306,974.51	68.00	328,040.51	63.92	20,967,289.30
2019	43,278,408.12	68.00	636,440.91	64.73	41,194,534.04
2020	47,671,238.78	68.00	701,040.73	65.54	45,946,439.11
2021	97,883,092.94	68.00	1,439,443.08	66.36	95,516,843.97
2022	149,392,564.57	68.00	2,196,927.85	67.18	147,583,894.41
2023	43,495,710.54	68.00	639,636.51	67.79	43,363,987.50
Total	866,289,998.01	68.00	12,739,433.38	58.15	740,768,900.33

Composite Average Remaining Life ... **58.15 Years**

Office of Utility Consumer Counselor
IURC Cause No. 46038
Data Request Set No. 24
Received: May 24, 2024

OUCC 24.3

Request:

Please refer to page 14, lines 1-11, of Petitioner's witness John J. Spanos' Direct testimony.

a. Please provide the amount Mr. Spanos allocated to depreciation reserve to account for the Cause No. 45253-S1 costs reversed by the Indiana Court of Appeals.
b. Please quantify the impact these costs have in establishing the depreciation accrual rates Mr. Spanos recommends.

Response:

Upon review of the depreciation study filed in this proceeding, it appears that the $92.1 million was inadvertently escalated when it was added to the depreciation study. Please refer to page 297 of Attachment 12-A(JJS) for the escalated figure of $122,575,419. Petitioner will correct this in its rebuttal testimony in this proceeding.

APPENDIX A:

THE DEPRECIATION SYSTEM

A depreciation accounting system may be thought of as a dynamic system in which estimates of life and salvage are inputs to the system, and the accumulated depreciation account is a measure of the state of the system at any given time.[1] The primary objective of the depreciation system is the timely recovery of capital. The process for calculating the annual accruals is determined by the factors required to define the system. A depreciation system should be defined by four primary factors: 1) a method of allocation; 2) a procedure for applying the method of allocation to a group of property; 3) a technique for applying the depreciation rate; and 4) a model for analyzing the characteristics of vintage groups comprising a continuous property group.[2] The figure below illustrates the basic concept of a depreciation system and includes some of the available parameters.[3]

There are hundreds of potential combinations of methods, procedures, techniques, and models, but in practice, analysts use only a few combinations. Ultimately, the system selected must result in the systematic and rational allocation of capital recovery for the utility. Each of the four primary factors defining the parameters of a depreciation system is discussed further below.

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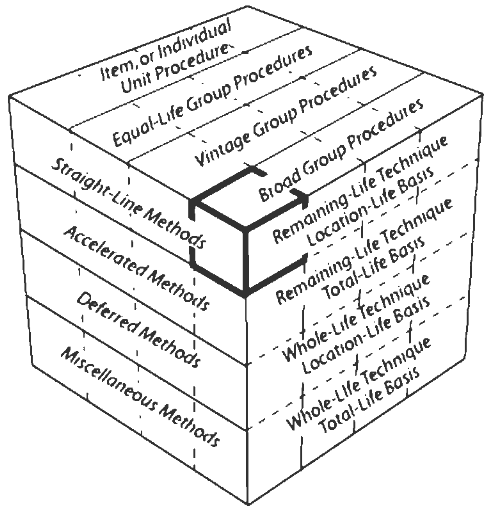
[1] Wolf & W. Chester Fitch, Depreciation Systems 69-70 (Iowa State University Press 1994).

[2] *Id.* at 70, 139–40.

[3] Edison Electric Institute, *Introduction to Depreciation* (inside cover) (EEI April 2013). Some definitions of the terms shown in this diagram are not consistent among depreciation practitioners and literature because depreciation analysis is a relatively small and fragmented field. This diagram simply illustrates some of the available parameters of a depreciation system.

Figure 1:
The Depreciation System Cube



1. Allocation Methods

The "method" refers to the pattern of depreciation in relation to the accounting periods. The method most commonly used in the regulatory context is the "straight-line method"—a type of age-life method in which the depreciable cost of plant is charged in equal amounts to each accounting period over the service life of plant.[4] Because group depreciation rates and plant balances often change, the amount of the annual accrual rarely remains the same, even when the straight-line method is employed.[5] The basic formula for the straight-line method is as follows:[6]

[4] National Association of Regulatory Utility Commissioners, Public Utility Depreciation Practices 56 (NARUC 1996).

[5] *Id*.

[6] *Id*.

Equation 1:
Straight-Line Accrual

$$Annual\ Accrual = \frac{Gross\ Plant - Net\ Salvage}{Service\ Life}$$

Gross plant is a known amount from the utility's records, while both net salvage and service life must be estimated to calculate the annual accrual. The straight-line method differs from accelerated methods of recovery, such as the "sum-of-the-years-digits" method and the "declining balance" method. Accelerated methods are primarily used for tax purposes and are rarely used in the regulatory context for determining annual accruals.[7] In practice, the annual accrual is expressed as a rate which is applied to the original cost of plant to determine the annual accrual in dollars. The formula for determining the straight-line rate is as follows:[8]

Equation 2:
Straight-Line Rate

$$Depreciation\ Rate\ \% = \frac{100 - Net\ Salvage\ \%}{Service\ Life}$$

2. Grouping Procedures

The "procedure" refers to the way the allocation method is applied through subdividing the total property into groups.[9] While single units may be analyzed for depreciation, a group plan of depreciation is particularly adaptable to utility property. Employing a grouping procedure allows for a composite application of depreciation rates to groups of similar property, rather than conducting calculations for each unit. Whereas an individual unit of property has a single life, a group of property displays a dispersion of lives and the life characteristics of the group must be

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[7] *Id*. at 57.

[8] *Id*. at 56.

[9] Wolf *supra* n. 1, at 74-75.

described statistically.[10] When analyzing mass property categories, it is important that each group contains homogenous units of plant that are used in the same general manner throughout the plant and operated under the same general conditions.[11]

The "average life" and "equal life" grouping procedures are the two most common. In the average life procedure, a constant annual accrual rate based on the average life of all property in the group is applied to the surviving property. While property having shorter lives than the group average will not be fully depreciated, and likewise, property having longer lives than the group average will be over-depreciated, the ultimate result is that the group will be fully depreciated by the time of the final retirement.[12] Thus, the average life procedure treats each unit as though its life is equal to the average life of the group. By contrast, the equal life procedure treats each unit in the group as though its life was known.[13] Under the equal life procedure the property is divided into subgroups that each has a common life.[14]

3. Application Techniques

The third factor of a depreciation system is the "technique" for applying the depreciation rate. There are two commonly used techniques: "whole life" and "remaining life." The whole life technique applies the depreciation rate on the estimated average service life of a group, while the remaining life technique seeks to recover undepreciated costs over the remaining life of the plant.[15]

In choosing the application technique, consideration should be given to the proper level of the accumulated depreciation account. Depreciation accrual rates are calculated using estimates

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[10] *Id*. at 74.

[11] NARUC *supra* n. 4, at 61–62.

[12] Wolf *supra* n. 1, at 74-75.

[13] *Id*. at 75.

[14] *Id*.

[15] NARUC *supra* n. 4, at 63–64.

of service life and salvage. Periodically these estimates must be revised due to changing conditions, which cause the accumulated depreciation account to be higher or lower than necessary. Unless some corrective action is taken, the annual accruals will not equal the original cost of the plant at the time of final retirement.[16] Analysts can calculate the level of imbalance in the accumulated depreciation account by determining the "calculated accumulated depreciation," (a.k.a. "theoretical reserve" and referred to in these appendices as "CAD"). The CAD is the calculated balance that would be in the accumulated depreciation account at a point in time using current depreciation parameters.[17] An imbalance exists when the actual accumulated depreciation account does not equal the CAD. The choice of application technique will affect how the imbalance is dealt with.

Use of the whole life technique requires that an adjustment be made to accumulated depreciation after calculation of the CAD. The adjustment can be made in a lump sum or over a period of time. With use of the remaining life technique, however, adjustments to accumulated depreciation are amortized over the remaining life of the property and are automatically included in the annual accrual.[18] This is one reason that the remaining life technique is popular among practitioners and regulators. The basic formula for the remaining life technique is as follows:[19]

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[16] Wolf *supra* n. 1, at 83.

[17] NARUC *supra* n. 4, at 325.

[18] NARUC *supra* n. 4, at 65 ("The desirability of using the remaining life technique is that any necessary adjustments of [accumulated depreciation] . . . are accrued automatically over the remaining life of the property. Once commenced, adjustments to the depreciation reserve, outside of those inherent in the remaining life rate would require regulatory approval.").

[19] *Id*. at 64.

Equation 3:
Remaining Life Accrual

$$Annual\ Accrual = \frac{Gross\ Plant - Accumulated\ Depreciation - Net\ Salvage}{Average\ Remaining\ Life}$$

The remaining life accrual formula is similar to the basic straight-line accrual formula above with two notable exceptions. First, the numerator has an additional factor in the remaining life formula: the accumulated depreciation. Second, the denominator is "average remaining life" instead of "average life." Essentially, the future accrual of plant (gross plant less accumulated depreciation) is allocated over the remaining life of plant. Thus, the adjustment to accumulated depreciation is "automatic" in the sense that it is built into the remaining life calculation.[20]

4. Analysis Model

The fourth parameter of a depreciation system, the "model," relates to the way of viewing the life and salvage characteristics of the vintage groups that have been combined to form a continuous property group for depreciation purposes.[21] A continuous property group is created when vintage groups are combined to form a common group. Over time, the characteristics of the property may change, but the continuous property group will continue. The two analysis models used among practitioners, the "broad group" and the "vintage group," are two ways of viewing the life and salvage characteristics of the vintage groups that have been combined to form a continuous property group.

The broad group model views the continuous property group as a collection of vintage groups that each have the same life and salvage characteristics. Thus, a single survivor curve and a single salvage schedule are chosen to describe all the vintages in the continuous property group.

[20] Wolf *supra* n. 1, at 178.

[21] *See* Wolf *supra* n. 1, at 139 (I added the term "model" to distinguish this fourth depreciation system parameter from the other three parameters).

By contrast, the vintage group model views the continuous property group as a collection of vintage groups that may have different life and salvage characteristics. Typically, there is not a significant difference between vintage group and broad group results unless vintages within the applicable property group experienced dramatically different retirement levels than anticipated in the overall estimated life for the group. For this reason, many analysts utilize the broad group procedure because it is more efficient.

APPENDIX B:

IOWA CURVES

Early work in the analysis of the service life of industrial property was based on models that described the life characteristics of human populations.[1] This history explains why the word "mortality" is often used in the context of depreciation analysis. In fact, a group of property installed during the same accounting period is analogous to a group of humans born during the same calendar year. Each period the group will incur a certain fraction of deaths / retirements until there are no survivors. Describing this pattern of mortality is part of actuarial analysis and is regularly used by insurance companies to determine life insurance premiums. The pattern of mortality may be described by several mathematical functions, particularly the survivor curve and frequency curve. Each curve may be derived from the other so that if one curve is known, the other may be obtained. A survivor curve is a graph of the percent of units remaining in service expressed as a function of age.[2] A frequency curve is a graph of the frequency of retirements as a function of age. Several types of survivor and frequency curves are illustrated in the figures below.

1. <u>Development</u>

The survivor curves used by analysts today were developed over several decades from extensive analysis of utility and industrial property. In 1931, Edwin Kurtz and Robley Winfrey used extensive data from a range of 65 industrial property groups to create survivor curves representing the life characteristics of each group of property.[3] They generalized the 65 curves into 13 survivor curve types and published their results in *Bulletin 103: Life Characteristics of Physical Property*. The 13 type curves were designed to be used as valuable aids in forecasting

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[1] Wolf & W. Chester Fitch, Depreciation Systems 276 (Iowa State University Press 1994).

[2] *Id*. at 23.

[3] *Id*. at 34.

probable future service lives of industrial property. Over the next few years, Winfrey continued gathering additional data, particularly from public utility property and expanded the examined property groups from 65 to 176.[4] This research resulted in 5 additional survivor curve types for a total of 18 curves. In 1935, Winfrey published *Bulletin 125: Statistical Analysis of Industrial Property Retirements*. According to Winfrey, "[t]he 18 type curves are expected to represent quite well all survivor curves commonly encountered in utility and industrial practices."[5] These curves are known as the "Iowa curves" and are used extensively in depreciation analysis in order to obtain the average service lives of property groups. (Use of Iowa curves in actuarial analysis is further discussed in Appendix C.)

In 1942, Winfrey published *Bulletin 155: Depreciation of Group Properties*. In Bulletin 155, Winfrey made some slight revisions to a few of the 18 curve types, and published the equations, tables of the percent surviving, and probable life of each curve at five-percent intervals.[6] Rather than using the original formulas, analysts typically rely on the published tables containing the percentages surviving. This reliance is necessary because, absent knowledge of the integration technique applied to each age interval, it is not possible to recreate the exact original published table values. In the 1970s, John Russo collected data from over 2,000 property accounts reflecting observations during the period 1965 – 1975 as part of his Ph.D. dissertation at Iowa State. Russo essentially repeated Winfrey's data collection, testing, and analysis methods used to develop the original Iowa curves, except that Russo studied industrial property in service several decades after

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[4] *Id*.

[5] Robley Winfrey, *Bulletin 125: Statistical Analyses of Industrial Property Retirements* 85, Vol. XXXIV, No. 23 (Iowa State College of Agriculture and Mechanic Arts 1935).

[6] Robley Winfrey, Bulletin 155: Depreciation of Group Properties 121-28, Vol XLI, No. 1 (The Iowa State College Bulletin 1942); see also Wolf supra n.7, at 305–38 (publishing the percent surviving for each Iowa curve, including "O" type curve, at one percent intervals).

Winfrey published the original Iowa curves. Russo drew three major conclusions from his research:[7]

1. No evidence was found to conclude that the Iowa curve set, as it stands, is not a valid system of standard curves;

2. No evidence was found to conclude that new curve shapes could be produced at this time that would add to the validity of the Iowa curve set; and

3. No evidence was found to suggest that the number of curves within the Iowa curve set should be reduced.

Prior to Russo's study, some had criticized the Iowa curves as being potentially obsolete because their development was rooted in the study of industrial property in existence during the early 1900s. Russo's research, however, negated this criticism by confirming that the Iowa curves represent a sufficiently wide range of life patterns and that, though technology will change over time, the underlying patterns of retirements remain constant and can be adequately described by the Iowa curves.[8]

Over the years, several more curve types have been added to Winfrey's 18 Iowa curves. In 1967, Harold Cowles added four origin-modal curves. In addition, a square curve is sometimes used to depict retirements which are all planned to occur at a given age. Finally, analysts commonly rely on several "half curves" derived from the original Iowa curves. Thus, the term "Iowa curves" could be said to describe up to 31 standardized survivor curves.

2. <u>Classification</u>

The Iowa curves are classified by three variables: modal location, average life, and variation of life. First, the mode is the percent life that results in the highest point of the frequency

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[7] *See* Wolf *supra* n. 1, at 37.

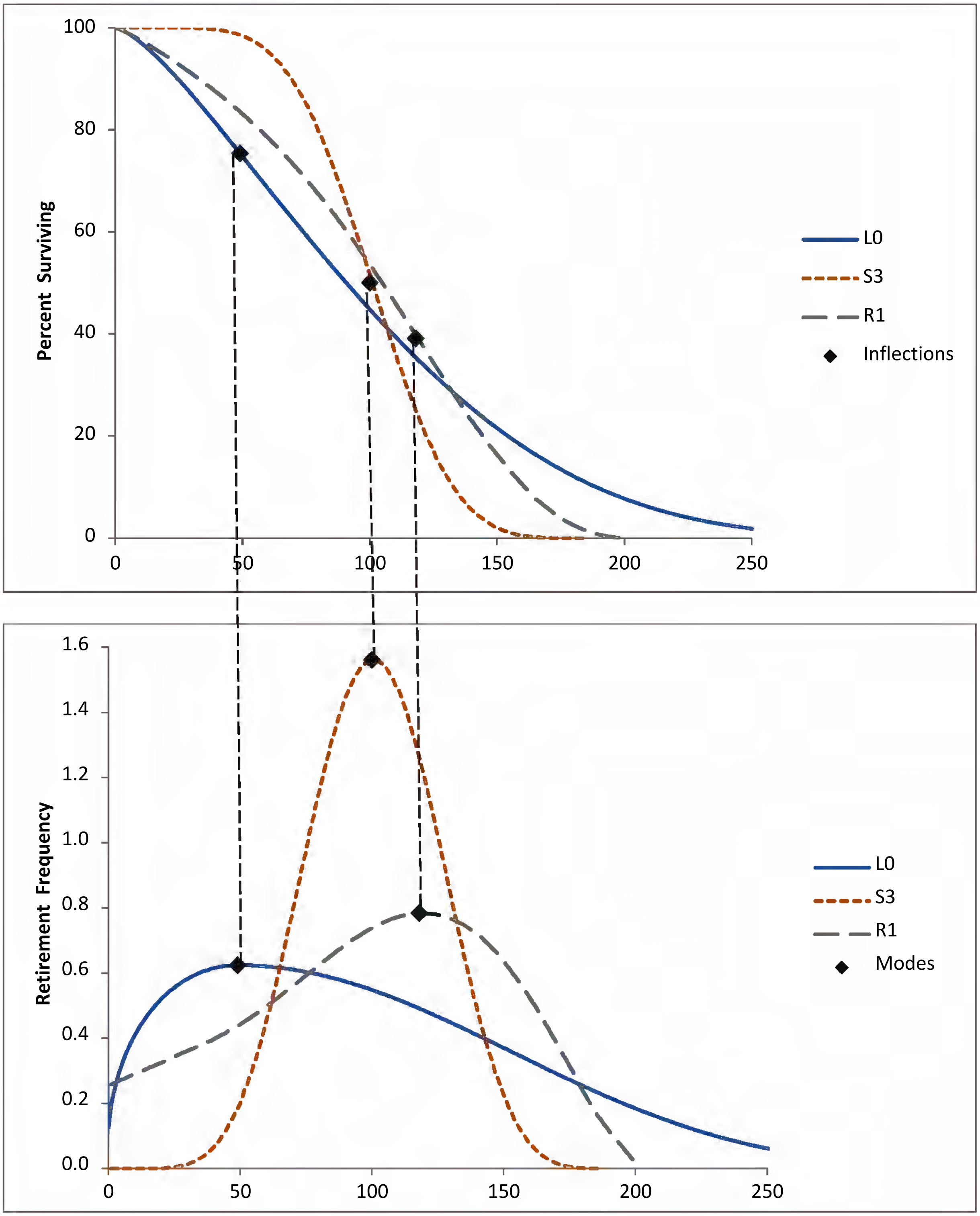
[8] *Id*.

curve and the "inflection point" on the survivor curve. The modal age is the age at which the greatest rate of retirement occurs. As illustrated in the figure below, the modes appear at the steepest point of each survivor curve in the top graph, as well as the highest point of each corresponding frequency curve in the bottom graph.

The classification of the survivor curves was made according to whether the mode of the retirement frequency curves was to the left, to the right, or coincident with average service life. There are three modal "families" of curves: six left modal curves (L0, L1, L2, L3, L4, L5); five right modal curves (R1, R2, R3, R4, R5); and seven symmetrical curves (S0, S1, S2, S3, S4, S5, S6).[9] In the figure below, one curve from each family is shown: L0, S3 and R1, with average life at 100 on the x-axis. It is clear from the graphs that the modes for the L0 and R1 curves appear to the left and right of average life respectively, while the S3 mode is coincident with average life.

[9] In 1967, Harold A. Cowles added four origin-modal curves known as "O type" curves. There are also several "half" curves and a square curve, so the total amount of survivor curves commonly called "Iowa" curves is about 31.

Figure 1:
Modal Age Illustration



The second Iowa curve classification variable is average life. The Iowa curves were designed using a single parameter of age expressed as a percent of average life instead of actual age. This design was necessary for the curves to be of practical value. As Winfrey notes:

> Since the location of a particular survivor on a graph is affected by both its span in years and the shape of the curve, it is difficult to classify a group of curves unless one of these variables can be controlled. This is easily done by expressing the age in percent of average life."[10]

Because age is expressed in terms of percent of average life, any particular Iowa curve type can be modified to forecast property groups with various average lives.

The third variable, variation of life, is represented by the numbers next to each letter. A lower number (e.g., L1) indicates a relatively low mode, large variation, and large maximum life; a higher number (e.g., L5) indicates a relatively high mode, small variation, and small maximum life. All three classification variables – modal location, average life, and variation of life – are used to describe each Iowa curve. For example, a 13-L1 Iowa curve describes a group of property with a 13-year average life, with the greatest number of retirements occurring before (or to the left of) the average life, and a relatively low mode. The graphs below show these 18 survivor curves, organized by modal family.

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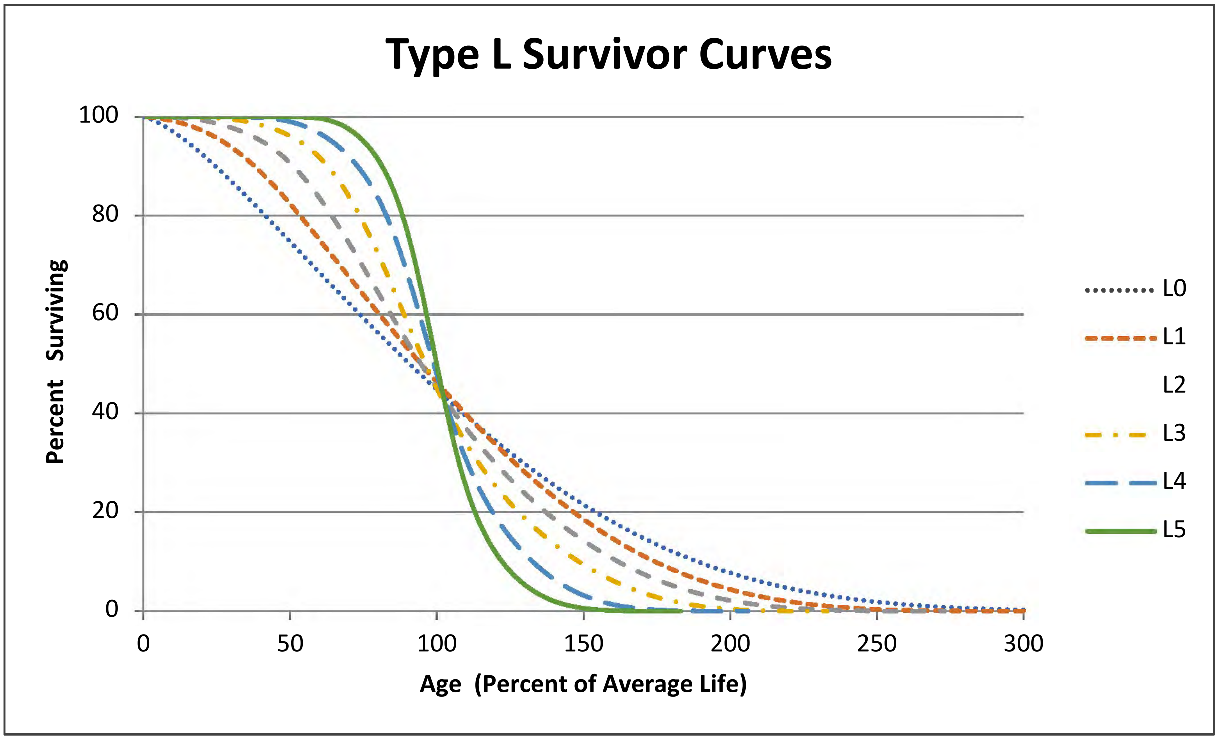
[10] Winfrey *supra* n. 6, at 60.

Figure 2:
Type L Survivor and Frequency Curves



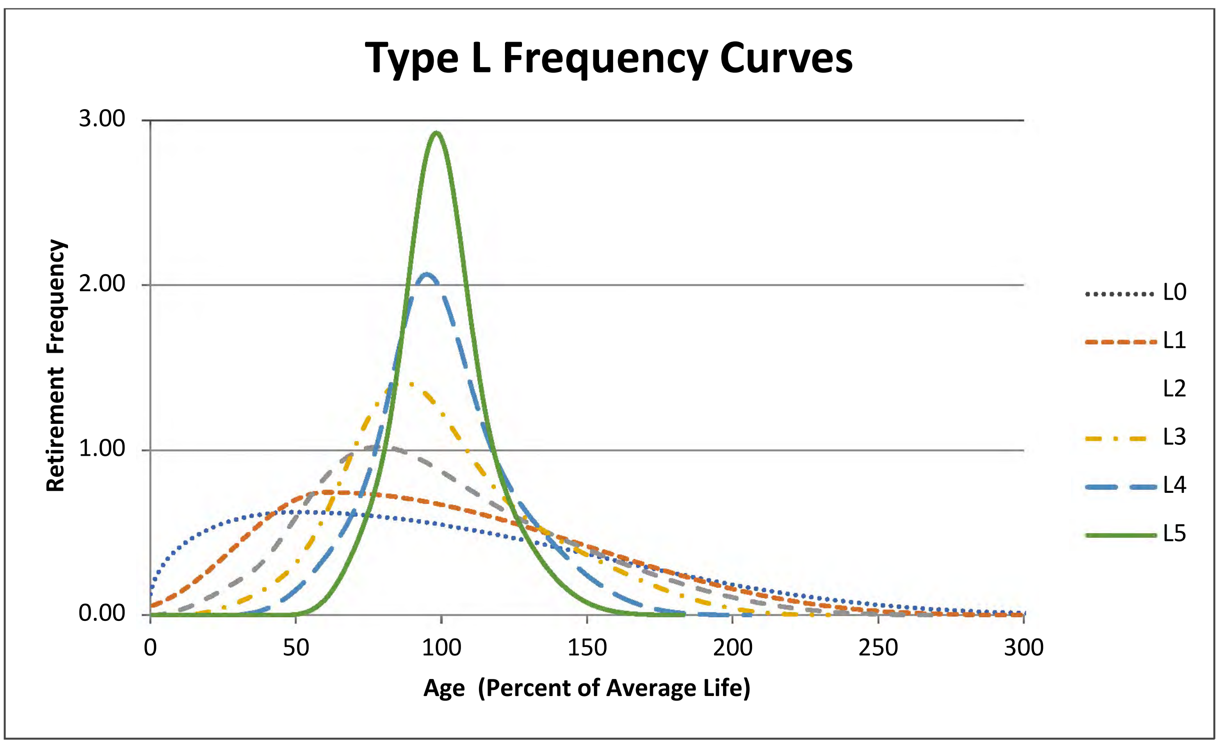
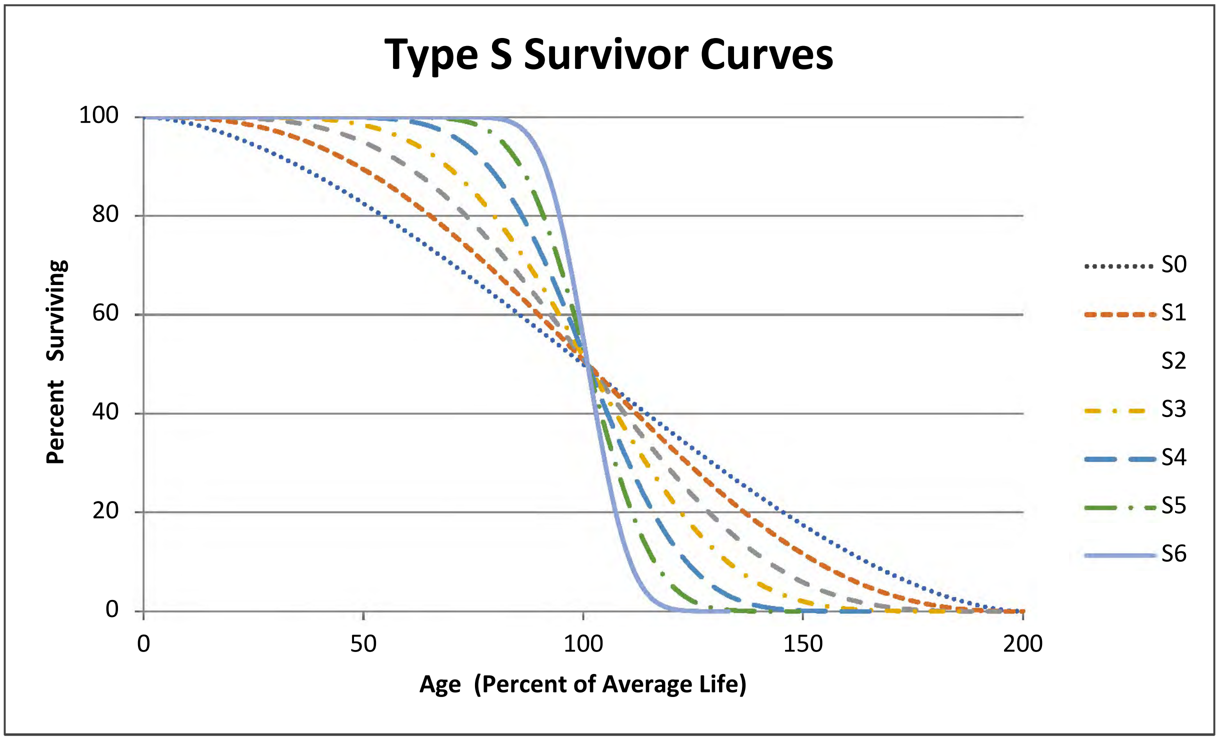


Figure 3:
Type S Survivor and Frequency Curves



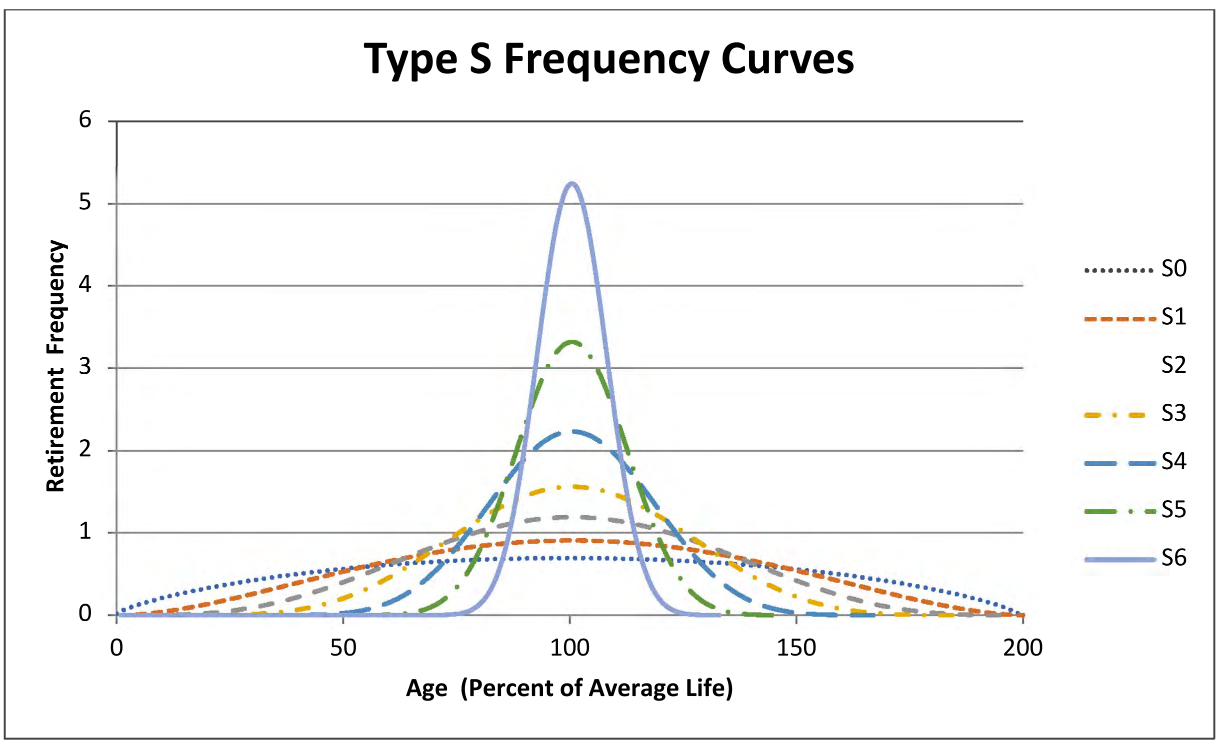
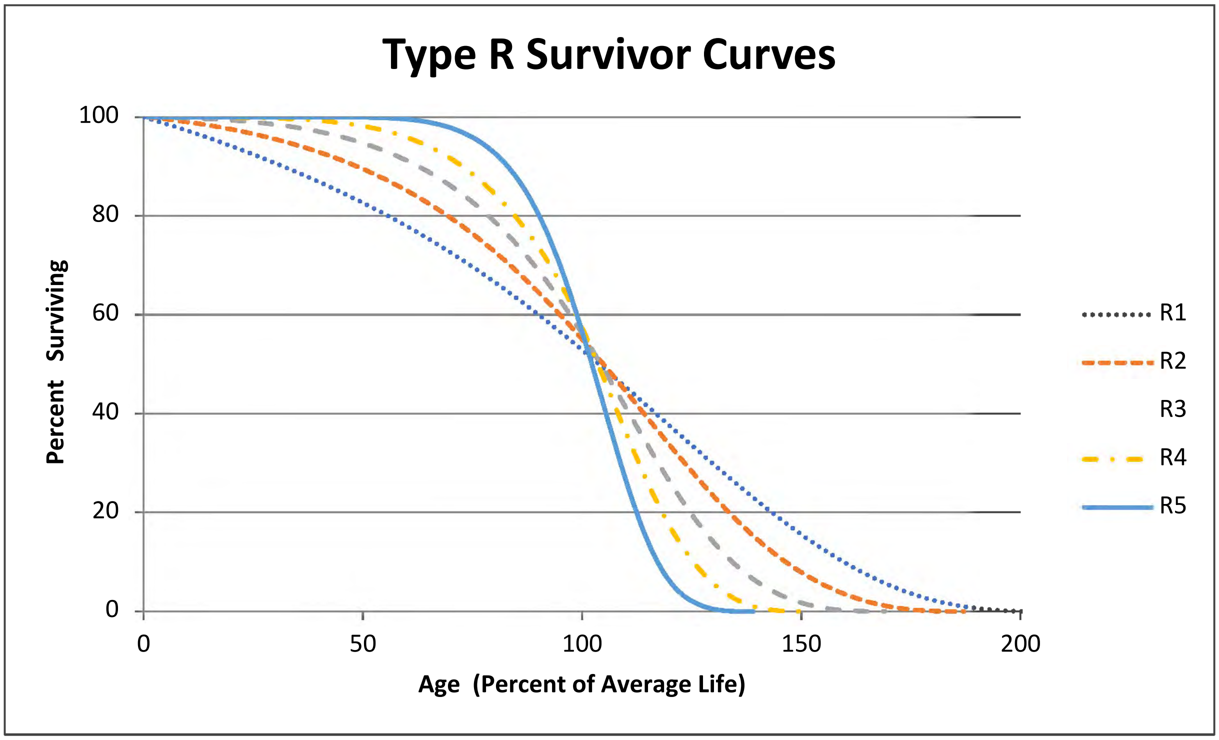
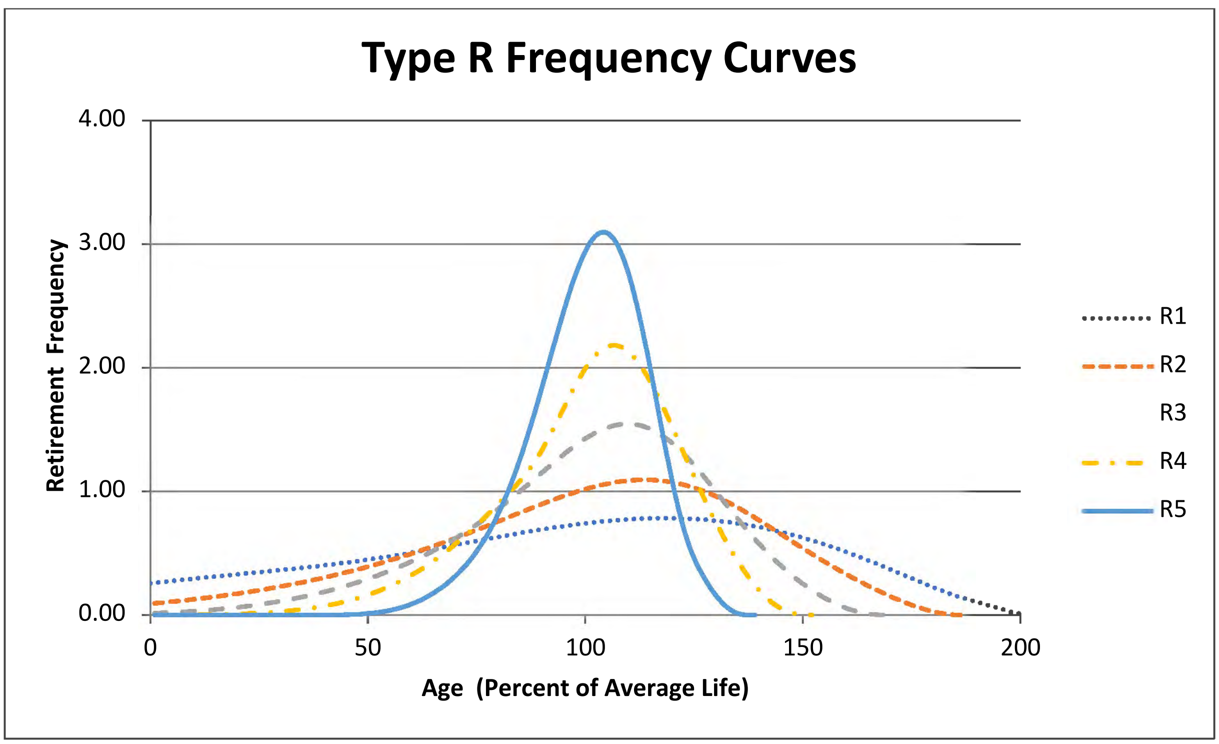


Figure 4:
Type R Survivor and Frequency Curves





As shown in the graphs above, the modes for the L family frequency curves occur to the left of average life (100% on the x-axis), while the S family modes occur at the average, and the R family modes occur after the average.

3. Types of Lives

Several other important statistical analyses and types of lives may be derived from an Iowa curve. These include: 1) average life; 2) realized life; 3) remaining life; and 4) probable life. The figure below illustrates these concepts. It shows the frequency curve, survivor curve, and probable life curve. Age M_x on the x-axis represents the modal age, while age AL_x represents the average age. Thus, this figure illustrates an "L type" Iowa curve since the mode occurs before the average.[11]

First, average life is the area under the survivor curve from age zero to maximum life. Because the survivor curve is measured in percent, the area under the curve must be divided by 100% to convert it from percent-years to years. The formula for average life is as follows:[12]

Equation 1:
Average Life

$$Average\ Life\ = \frac{Area\ Under\ Survivor\ Curve\ from\ Age\ 0\ to\ Max\ Life}{100\%}$$

Thus, average life may not be determined without a complete survivor curve. Many property groups being analyzed will not have experienced full retirement. This dynamic results in a "stub" survivor curve. Iowa curves are used to extend stub curves to maximum life in order to make the average life calculation (see Appendix C).

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[11] From age zero to age M_x on the survivor curve, it could be said that the percent surviving from this property group is decreasing at an increasing rate. Conversely, from point M_x to maximum on the survivor curve, the percent surviving is decreasing at a decreasing rate.

[12] National Association of Regulatory Utility Commissioners, Public Utility Depreciation Practices 71 (NARUC 1996).

Realized life is similar to average life, except that realized life is the average years of service experienced to date from the vintage's original installations.[13] As shown in the figure below, realized life is the area under the survivor curve from zero to age RL_X. Likewise, unrealized life is the area under the survivor curve from age RL_X to maximum life. Thus, it could be said that average life equals realized life plus unrealized life.

Average remaining life represents the future years of service expected from the surviving property.[14] Remaining life is sometimes referred to as "average remaining life" and "life expectancy." To calculate average remaining life at age x, the area under the estimated future portion of the survivor curve is divided by the percent surviving at age x (denoted S_X). Thus, the average remaining life formula is:

Equation 2:
Average Remaining Life

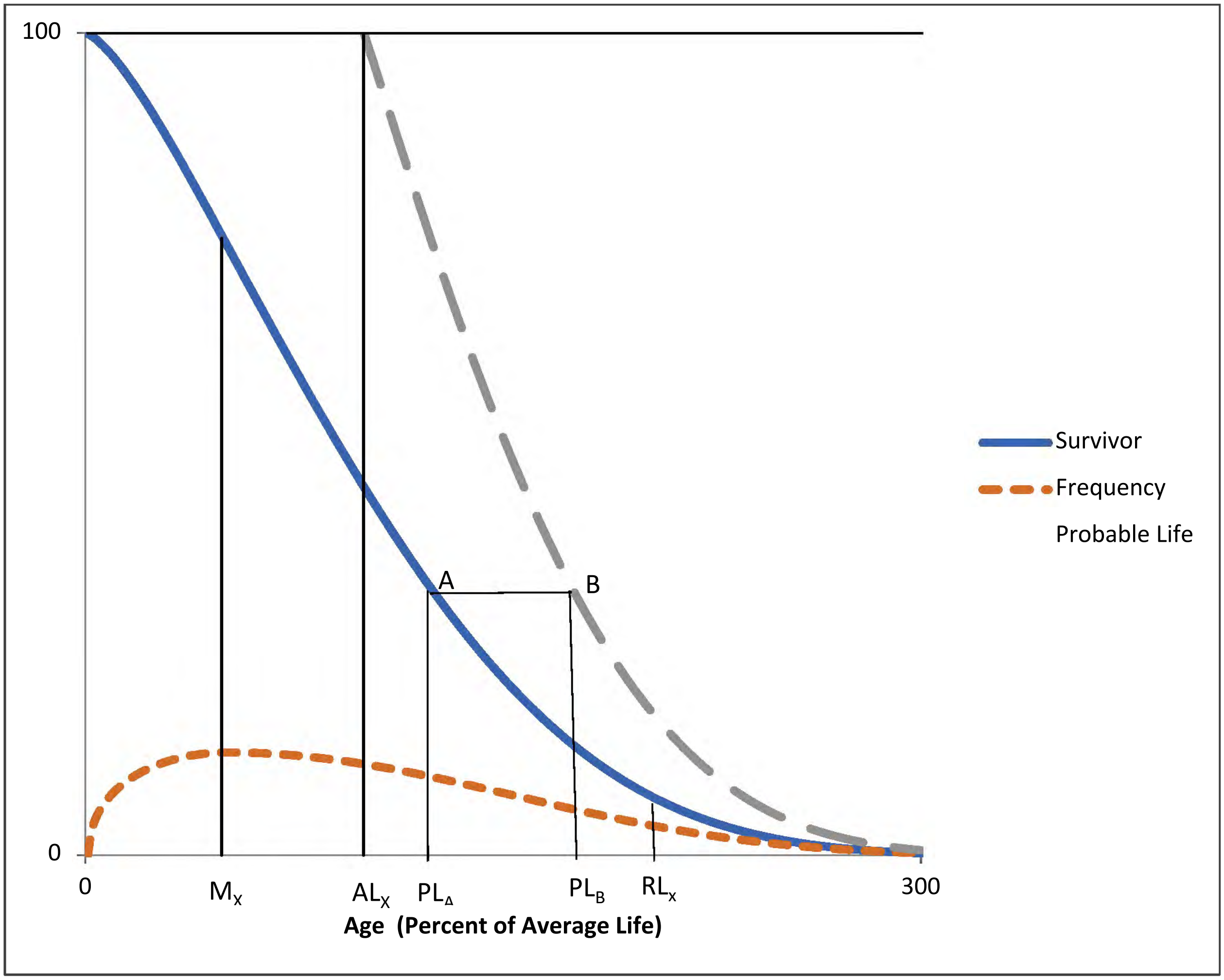
$$Average\ Remaining\ Life = \frac{Area\ Under\ Survivor\ Curve\ from\ Age\ x\ to\ Max\ Life}{S_X}$$

It is necessary to determine average remaining life to calculate the annual accrual under the remaining life technique.

[13] *Id*. at 73.

[14] *Id*. at 74.

Figure 5:
Iowa Curve Derivations



Finally, the probable life may also be determined from the Iowa curve. The probable life of a property group is the total life expectancy of the property surviving at any age and is equal to the remaining life plus the current age.[15] The probable life is also illustrated in this figure. The probable life at age PL_A is the age at point PL_B. Thus, to read the probable life at age PL_A, see the corresponding point on the survivor curve above at point "A," then horizontally to point "B" on

15 Wolf *supra* n. 1, at 28.

the probable life curve, and back down to the age corresponding to point "B." It is no coincidence that the vertical line from AL_X connects at the top of the probable life curve. This connection occurs because at age zero, probable life equals average life.

APPENDIX C:

ACTUARIAL ANALYSIS

Actuarial science is a discipline that applies various statistical methods to assess risk probabilities and other related functions. Actuaries often study human mortality. The results from historical mortality data are used to predict how long similar groups of people who are alive today will live. Insurance companies rely on actuarial analysis in determining premiums for life insurance policies.

The study of human mortality is analogous to estimating service lives of industrial property groups. While some humans die solely from chance, most deaths are related to age; that is, death rates generally increase as age increases. Similarly, physical plant is also subject to forces of retirement. These forces include physical, functional, and contingent factors, as shown in the table below.[1]

Figure 1:
Forces of Retirement

Physical Factors	Functional Factors	Contingent Factors
Wear and tear Decay or deterioration Action of the elements	Inadequacy Obsolescence Changes in technology Regulations Managerial discretion	Casualties or disasters Extraordinary obsolescence

While actuaries study historical mortality data in order to predict how long a group of people will live, depreciation analysts must look at a utility's historical data in order to estimate the average lives of property groups. A utility's historical data is often contained in the Continuing

[1] National Association of Regulatory Utility Commissioners, Public Utility Depreciation Practices 14-15 (NARUC 1996).

Property Records ("CPR"). Generally, a CPR should contain 1) an inventory of property record units; 2) the association of costs with such units; and 3) the dates of installation and removal of plant. Since actuarial analysis includes the examination of historical data to forecast future retirements, the historical data used in the analysis should not contain events that are anomalous or unlikely to recur.[2] Historical data is used in the retirement rate actuarial method, which is discussed further below.

<u>The Retirement Rate Method</u>

There are several systematic actuarial methods that use historical data to calculate observed survivor curves for property groups. Of these methods, the retirement rate method is superior, and is widely employed by depreciation analysts.[3] The retirement rate method is ultimately used to develop an observed survivor curve, which can be fitted with an Iowa curve discussed in Appendix B to forecast average life. The observed survivor curve is calculated by using an observed life table ("OLT"). The figures below illustrate how the OLT is developed. First, historical property data are organized in a matrix format, with placement years on the left forming rows, and experience years on the top forming columns. The placement year (a.k.a. "vintage year" or "installation year") is the year of placement into service of a group of property. The experience year (a.k.a. "activity year") refers to the accounting data for a particular calendar year. The two matrices below use aged data—that is, data for which the dates of placements, retirements, transfers, and other transactions are known. Without aged data, the retirement rate actuarial method may not be employed. The first matrix is the exposure matrix, which shows the exposures

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[2] *Id*. at 112–13.

[3] Anson Marston, Robley Winfrey & Jean C. Hempstead, *Engineering Valuation and Depreciation* 154 (2nd ed., McGraw-Hill Book Company, Inc. 1953).

at the beginning of each year.[4] An exposure is simply the depreciable property subject to retirement during a period. The second matrix is the retirement matrix, which shows the annual retirements during each year. Each matrix covers placement years 2003–2015, and experience years 2008–2015. In the exposure matrix, the number in the 2012 experience column and the 2003 placement row is $192,000. This means at the beginning of 2012, there was $192,000 still exposed to retirement from the vintage group placed in 2003. Likewise, in the retirement matrix, $19,000 of the dollars invested in 2003 were retired during 2012.

Figure 2:
Exposure Matrix

	Experience Years									
	Exposures at January 1 of Each Year (Dollars in 000's)									
Placement Years	2008	2009	2010	2011	2012	2013	2014	2015	Total at Start of Age Interval	Age Interval
2003	261	245	228	211	**192**	173	152	131	131	11.5 - 12.5
2004	267	252	236	220	202	**184**	165	145	297	10.5 - 11.5
2005	304	291	277	263	248	232	**216**	198	536	9.5 - 10.5
2006	345	334	322	310	298	284	270	**255**	**847**	8.5 - 9.5
2007	367	357	347	335	324	312	299	286	1,201	7.5 - 8.5
2008	375	366	357	347	336	325	314	302	1,581	6.5 - 7.5
2009		377	366	356	346	336	327	319	1,986	5.5 - 6.5
2010			381	369	358	347	336	327	2,404	4.5 - 5.5
2011				386	372	359	346	334	2,559	3.5 - 4.5
2012					395	380	366	352	2,722	2.5 - 3.5
2013						401	385	370	2,866	1.5 - 2.5
2014							410	393	2,998	0.5 - 1.5
2015								416	3,141	0.0 - 0.5
Total	1919	2222	2514	2796	3070	3333	3586	3827	23,268	

[4] Technically, the last numbers in each column are "gross additions" rather than exposures. Gross additions do not include adjustments and transfers applicable to plant placed in a previous year. Once retirements, adjustments, and transfers are factored in, the balance at the beginning of the next accounting period is called an "exposure" rather than an addition.

Figure 3:
Retirement Matrix

Placement Years	Experience Years Retirements During the Year (000's) 2008	2009	2010	2011	2012	2013	2014	2015	Total at Start of Age Interval	Age Interval
2003	16	17	18	19	19	20	21	23	23	11.5 - 12.5
2004	15	16	17	17	18	19	20	21	43	10.5 - 11.5
2005	13	14	14	15	16	17	17	18	59	9.5 - 10.5
2006	11	12	12	13	13	14	15	15	71	8.5 - 9.5
2007	10	11	11	12	12	13	13	14	82	7.5 - 8.5
2008	9	9	10	10	11	11	12	13	91	6.5 - 7.5
2009		11	10	10	9	9	9	8	95	5.5 - 6.5
2010			12	11	11	10	10	9	100	4.5 - 5.5
2011				14	13	13	12	11	93	3.5 - 4.5
2012					15	14	14	13	91	2.5 - 3.5
2013						16	15	14	93	1.5 - 2.5
2014							17	16	100	0.5 - 1.5
2015								18	112	0.0 - 0.5
Total	74	89	104	121	139	157	175	194	1,052	

These matrices help visualize how exposure and retirement data are calculated for each age interval. An age interval is typically one year. A common convention is to assume that any unit installed during the year is installed in the middle of the calendar year (i.e., July 1st). This convention is called the "half-year convention" and effectively assumes that all units are installed uniformly during the year.[5] Adoption of the half-year convention leads to age intervals of 0–0.5 years, 0.5–1.5 years, etc., as shown in the matrices.

The purpose of the matrices is to calculate the totals for each age interval, which are shown in the second column from the right in each matrix. This column is calculated by adding each number from the corresponding age interval in the matrix. For example, in the exposure matrix, the total amount of exposures at the beginning of the 8.5–9.5 age interval is $847,000. This number was calculated by adding the numbers shown on the "stairs" to the left (192+184+216+255=847).

[5] Frank K. Wolf & W. Chester Fitch, Depreciation Systems 22 (Iowa State University Press 1994).

The same calculation is applied to each number in the column. The amounts retired during the year in the retirements matrix affect the exposures at the beginning of each year in the exposures matrix. For example, the amount exposed to retirement in 2008 from the 2003 vintage is $261,000. The amount retired during 2008 from the 2003 vintage is $16,000. Thus, the amount exposed to retirement at the beginning of 2009 from the 2003 vintage is $245,000 ($261,000 - $16,000). The company's property records may contain other transactions which affect the property, including sales, transfers, and adjusting entries. Although these transactions are not shown in the matrices above, they would nonetheless affect the amount exposed to retirement at the beginning of each year.

The totaled amounts for each age interval in both matrices are used to form the exposure and retirement columns in the OLT, as shown in the chart below. This chart also shows the retirement ratio and the survivor ratio for each age interval. The retirement ratio for an age interval is the ratio of retirements during the interval to the property exposed to retirement at the beginning of the interval. The retirement ratio represents the probability that the property surviving at the beginning of an age interval will be retired during the interval. The survivor ratio is simply the complement to the retirement ratio (1 – retirement ratio). The survivor ratio represents the probability that the property surviving at the beginning of an age interval will survive to the next age interval.

Figure 4:
Observed Life Table

Age at Start of Interval	Exposures at Start of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Start of Age Interval
A	B	C	D = C / B	E = 1 - D	F
0.0	3,141	112	0.036	0.964	**100.00**
0.5	2,998	100	0.033	0.967	**96.43**
1.5	2,866	93	0.032	0.968	**93.21**
2.5	2,722	91	0.033	0.967	**90.19**
3.5	2,559	93	0.037	0.963	**87.19**
4.5	2,404	100	0.042	0.958	**84.01**
5.5	1,986	95	0.048	0.952	**80.50**
6.5	1,581	91	0.058	0.942	**76.67**
7.5	1,201	82	0.068	0.932	**72.26**
8.5	847	71	0.084	0.916	**67.31**
9.5	536	59	0.110	0.890	**61.63**
10.5	297	43	0.143	0.857	**54.87**
11.5	131	23	0.172	0.828	**47.01**
					38.91
Total	23,268	1,052			

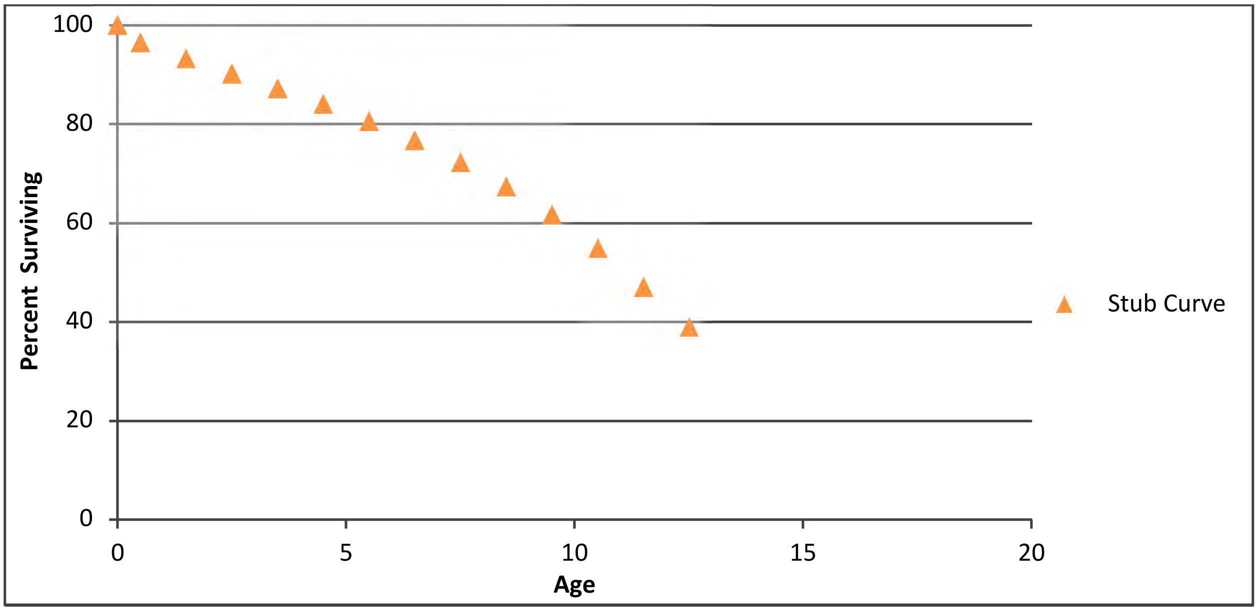
Column F on the right shows the percentages surviving at the beginning of each age interval. This column starts at 100 percent surviving. Each consecutive number below is calculated by multiplying the percent surviving from the previous age interval by the corresponding survivor ratio for that age interval. For example, the percent surviving at the start of age interval 1.5 is 93.21 percent, which was calculated by multiplying the percent surviving for age interval 0.5 (96.43 percent) by the survivor ratio for age interval 0.5 (0.967).[6]

The percentages surviving in Column F are the numbers that are used to form the original survivor curve. This particular curve starts at 100 percent surviving and ends at 38.91 percent surviving. An observed survivor curve such as this that does not reach zero percent surviving is

[6] Multiplying 96.43 by 0.967 does not equal 93.21 exactly due to rounding.

called a "stub" curve. The figure below illustrates the stub survivor curve derived from the OLT above.

Figure 5:
Original "Stub" Survivor Curve



The matrices used to develop the basic OLT and stub survivor curve provide a basic illustration of the retirement rate method in that only a few placement and experience years were used. In reality, analysts may have several decades of aged property data to analyze. In that case, it may be useful to use a technique called "banding" in order to identify trends in the data.

<u>Banding</u>

The forces of retirement and characteristics of industrial property are constantly changing. A depreciation analyst may examine the magnitude of these changes. Analysts often use a technique called "banding" to assist with this process. Banding refers to the merging of several years of data into a single data set for further analysis, and it is a common technique associated with the retirement rate method.[7] There are three primary benefits of using bands in depreciation analysis:

1. Increasing the sample size. In statistical analyses, the larger the sample size in relation to the body of total data, the greater the reliability of the result;

2. Smooth the observed data. Generally, the data obtained from a single activity or vintage year will not produce an observed life table that can be easily fit; and

3. Identify trends. By looking at successive bands, the analyst may identify broad trends in the data that may be useful in projecting the future life characteristics of the property.[8]

Two common types of banding methods are the "placement band" method and the "experience band" method." A placement band, as the name implies, isolates selected placement years for analysis. The figure below illustrates the same exposure matrix shown above, except that only the placement years 2005–2008 are considered in calculating the total exposures at the beginning of each age interval.

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[7] NARUC *supra* n. 1, at 113.

[8] *Id*.

Figure 6:
Placement Bands

Placement Years	Experience Years Exposures at January 1 of Each Year (Dollars in 000's) 2008	2009	2010	2011	2012	2013	2014	2015	Total at Start of Age Interval	Age Interval
2003	261	245	228	211	192	173	152	131		11.5 - 12.5
2004	267	252	236	220	202	184	165	145		10.5 - 11.5
2005	304	291	277	263	248	232	216	198	198	9.5 - 10.5
2006	345	334	322	310	298	284	270	255	471	8.5 - 9.5
2007	367	357	347	335	324	312	299	286	788	7.5 - 8.5
2008	375	366	357	347	336	325	314	302	1,133	6.5 - 7.5
2009		377	366	356	346	336	327	319	1,186	5.5 - 6.5
2010			381	369	358	347	336	327	1,237	4.5 - 5.5
2011				386	372	359	346	334	1,285	3.5 - 4.5
2012					395	380	366	352	1,331	2.5 - 3.5
2013						401	385	370	1,059	1.5 - 2.5
2014							410	393	733	0.5 - 1.5
2015								416	375	0.0 - 0.5
Total	1919	2222	2514	2796	3070	3333	3586	3827	9,796	

The shaded cells within the placement band equal the total exposures at the beginning of age interval 4.5–5.5 ($1,237). The same placement band would be used for the retirement matrix covering the same placement years of 2005–2008. This use of course would result in a different OLT and original stub survivor curve than those that were calculated above without the restriction of a placement band.

Analysts often use placement bands for comparing the survivor characteristics of properties with different physical characteristics.[9] Placement bands allow analysts to isolate the effects of changes in technology and materials that occur in successive generations of plant. For example, if in 2005 an electric utility began placing transmission poles into service with a special chemical treatment that extended the service lives of those poles, an analyst could use placement bands to isolate and analyze the effect of that change in the property group's physical characteristics. While placement bands are very useful in depreciation analysis, they also possess an intrinsic dilemma.

[9] Wolf *supra* n. 5, at 182.

A fundamental characteristic of placement bands is that they yield fairly complete survivor curves for older vintages. However, with newer vintages, which are arguably more valuable for forecasting, placement bands yield shorter survivor curves. Longer "stub" curves are considered more valuable for forecasting average life. Thus, an analyst must select a band width broad enough to provide confidence in the reliability of the resulting curve fit yet narrow enough so that an emerging trend may be observed.[10]

Analysts also use "experience bands." Experience bands show the composite retirement history for all vintages during a select set of activity years. The figure below shows the same data presented in the previous exposure matrices, except that the experience band from 2011–2013 is isolated, resulting in different interval totals.

Figure 7:
Experience Bands

	Experience Years Exposures at January 1 of Each Year (Dollars in 000's)									
Placement Years	2008	2009	2010	2011	2012	2013	2014	2015	Total at Start of Age Interval	Age Interval
2003	261	245	228	211	192	173	152	131		11.5 - 12.5
2004	267	252	236	220	202	184	165	145		10.5 - 11.5
2005	304	291	277	263	248	232	216	198	173	9.5 - 10.5
2006	345	334	322	310	298	284	270	255	376	8.5 - 9.5
2007	367	357	347	335	324	312	299	286	645	7.5 - 8.5
2008	375	366	357	347	336	325	314	302	752	6.5 - 7.5
2009		377	366	356	346	336	327	319	872	5.5 - 6.5
2010			381	369	358	347	336	327	959	4.5 - 5.5
2011				386	372	359	346	334	1,008	3.5 - 4.5
2012					395	380	366	352	1,039	2.5 - 3.5
2013						401	385	370	1,072	1.5 - 2.5
2014							410	393	1,121	0.5 - 1.5
2015								416	1,182	0.0 - 0.5
Total	1919	2222	2514	2796	3070	3333	3586	3827	9,199	

The shaded cells within the experience band equal the total exposures at the beginning of age interval 4.5–5.5 ($1,237). The same experience band would be used for the retirement matrix

[10] NARUC *supra* n. 1, at 114.

covering the same experience years of 2011–2013. This use of course would result in a different OLT and original stub survivor than if the band had not been used. Analysts often use experience bands to isolate and analyze the effects of an operating environment over time.[11] Likewise, the use of experience bands allows analysis of the effects of an unusual environmental event. For example, if an unusually severe ice storm occurred in 2013, destruction from that storm would affect an electric utility's line transformers of all ages. That is, each of the line transformers from each placement year would be affected, including those recently installed in 2012, as well as those installed in 2003. Using experience bands, an analyst could isolate or even eliminate the 2013 experience year from the analysis. In contrast, a placement band would not effectively isolate the ice storm's effect on life characteristics. Rather, the placement band would show an unusually large rate of retirement during 2013, making it more difficult to accurately fit the data with a smooth Iowa curve. Experience bands tend to yield the most complete stub curves for recent bands because they have the greatest number of vintages included. Longer stub curves are better for forecasting. The experience bands, however, may also result in more erratic retirement dispersion making the curve-fitting process more difficult.

Depreciation analysts must use professional judgment in determining the types of bands to use and the band widths. In practice, analysts may use various combinations of placement and experience bands in order to increase the data sample size, identify trends and changes in life characteristics, and isolate unusual events. Regardless of which bands are used, observed survivor curves in depreciation analysis rarely reach zero percent. They rarely reach zero percent because, as seen in the OLT above, relatively newer vintage groups have not yet been fully retired at the

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[11] *Id*.

time the property is studied. An analyst could confine the analysis to older, fully retired vintage groups to get complete survivor curves, but such analysis would ignore some of the property currently in service and would arguably not provide an accurate description of life characteristics for current plant in service. Because a complete curve is necessary to calculate the average life of the property group, however, curve-fitting techniques using Iowa curves or other standardized curves may be employed in order to complete the stub curve.

Curve Fitting

Depreciation analysts typically use the survivor curve rather than the frequency curve to fit the observed stub curves. The most commonly used generalized survivor curves in the curve-fitting process are the Iowa curves discussed above. As Wolf notes, if "the Iowa curves are adopted as a model, an underlying assumption is that the process describing the retirement pattern is one of the 22 [or more] processes described by the Iowa curves."[12]

Curve fitting may be done through visual matching or mathematical matching. In visual curve fitting, the analyst visually examines the plotted data to make an initial judgment about the Iowa curves that may be a good fit. The figure below illustrates the stub survivor curve shown above. It also shows three different Iowa curves: the 10-L4, the 10.5-R1, and the 10-S0. Visually, the 10.5-R1 curve is clearly a better fit than the other two curves.

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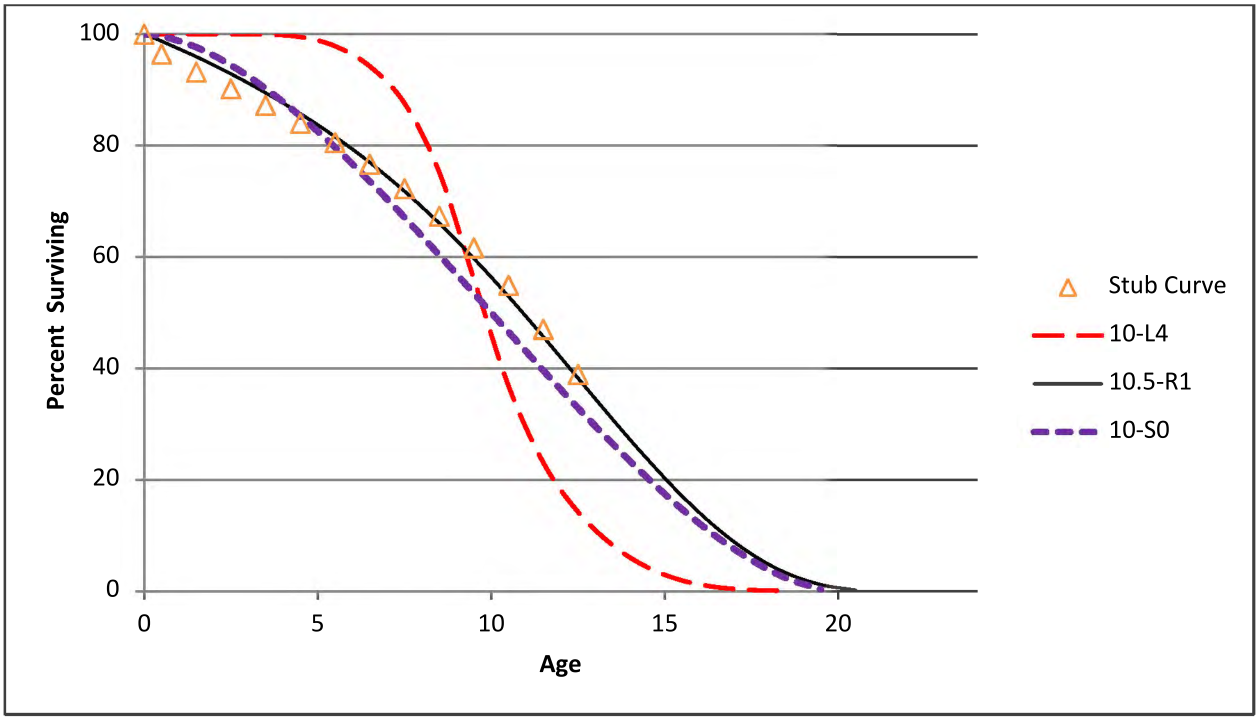
[12] Wolf *supra* n. 5, at 46 (22 curves includes Winfrey's 18 original curves plus Cowles's four "O" type curves).

Figure 8:
Visual Curve Fitting



In mathematical fitting, the least squares method is used to calculate the best fit. This mathematical method would be excessively time consuming if done by hand. With the use of modern computer software however, mathematical fitting is an efficient and useful process. The typical logic for a computer program, as well as the software employed for the analysis in this testimony is as follows:

> First (an Iowa curve) curve is arbitrarily selected. . . . If the observed curve is a stub curve, . . . calculate the area under the curve and up to the age at final data point. Call this area the realized life. Then systematically vary the average life of the theoretical survivor curve and calculate its realized life at the age corresponding to the study date. This trial and error procedure ends when you find an average life such that the realized life of the theoretical curve equals the realized life of the observed curve. Call this the average life.
>
> Once the average life is found, calculate the difference between each percent surviving point on the observed survivor curve and the corresponding point on the Iowa curve. Square each difference and sum them. The sum of squares is used as a measure of goodness of fit for that particular Iowa type curve. This procedure is

> repeated for the remaining 21 Iowa type curves. The "best fit" is declared to be the type of curve that minimizes the sum of differences squared.[13]

Mathematical fitting requires less judgment from the analyst and is thus less subjective. Blind reliance on mathematical fitting, however, may lead to poor estimates. Thus, analysts should employ both mathematical and visual curve fitting in reaching their final estimates. This way, analysts may utilize the objective nature of mathematical fitting while still employing professional judgment. As Wolf notes: "The results of mathematical curve fitting serve as a guide for the analyst and speed the visual fitting process. But the results of the mathematical fitting should be checked visually, and the final determination of the best fit be made by the analyst."[14]

In the graph above, visual fitting was sufficient to determine that the 10.5-R1 Iowa curve was a better fit than the 10-L4 and the 10-S0 curves. Using the sum of least squares method, mathematical fitting confirms the same result. In the chart below, the percentages surviving from the OLT that formed the original stub curve are shown in the left column, while the corresponding percentages surviving for each age interval are shown for the three Iowa curves. The right portion of the chart shows the differences between the points on each Iowa curve and the stub curve. These differences are summed at the bottom. Curve 10.5-R1 is the best fit because the sum of the squared differences for this curve is less than the same sum for the other two curves. Curve 10-L4 is the worst fit, which was also confirmed visually.

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[13] Wolf *supra* n. 5, at 47.

[14] *Id*. at 48.

Figure 9:
Mathematical Fitting

Age Interval	Stub Curve	Iowa Curves 10-L4	Iowa Curves 10-S0	Iowa Curves 10.5-R1	Squared Differences 10-L4	Squared Differences 10-S0	Squared Differences 10.5-R1
0.0	100.0	100.0	100.0	100.0	0.0	0.0	0.0
0.5	96.4	100.0	99.7	98.7	12.7	10.3	5.3
1.5	93.2	100.0	97.7	96.0	46.1	19.8	7.6
2.5	90.2	100.0	94.4	92.9	96.2	18.0	7.2
3.5	87.2	100.0	90.2	89.5	162.9	9.3	5.2
4.5	84.0	99.5	85.3	85.7	239.9	1.6	2.9
5.5	80.5	97.9	79.7	81.6	301.1	0.7	1.2
6.5	76.7	94.2	73.6	77.0	308.5	9.5	0.1
7.5	72.3	87.6	67.1	71.8	235.2	26.5	0.2
8.5	67.3	75.2	60.4	66.1	62.7	48.2	1.6
9.5	61.6	56.0	53.5	59.7	31.4	66.6	3.6
10.5	54.9	36.8	46.5	52.9	325.4	69.6	3.9
11.5	47.0	23.1	39.6	45.7	572.6	54.4	1.8
12.5	38.9	14.2	32.9	38.2	609.6	36.2	0.4
SUM					**3004.2**	**371.0**	**41.0**

CERTIFICATE OF SERVICE

This is to certify that a copy of the foregoing ***Indiana Office of Utility Consumer Counselor Public's Exhibit No. 8 Testimony of OUCC Witness David J. Garrett*** has been served upon the following counsel of record in the captioned proceeding by electronic service on July 11, 2024.

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