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Society of Depreciation Professionals
Goals and Objectives

Overall Goals

The objectives of the society shall be to recognize the professional field of depreciation and those individuals contributing to this field; to promote the professional development and professional ethics of those practitioners in the field of depreciation; to collect and exchange information about depreciation engineering and analysis; to provide a national forum of programs and publications concerning depreciation.

Activities

·Provide a forum for discussion of issues relating to depreciation policy.
·Recognize professionalism through membership and awards for service and contributions to the art of depreciation.
·Encourage papers on matters of interest to depreciation professionals.
·Sponsor regular conferences.
·Provide members with information and training that will enhance their skills as depreciation professionals.
·Sanction individually, or jointly with other organizations, educational forums on depreciation.
·Publish a regular newsletter.
·Provide electronic data sources such as internet communication or other electronic data services.

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SUMMARY OF ABSTRACTS

Life Spans of Electric Generating Units
John S. Ferguson

Predictions of the life spans of electric generating units have been useful for numerous purposes, and the current electric industry restructuring has given such predictions added importance. An understanding of the past can be of value when attempting to predict the future. This article utilizes two sources of data on experienced generating unit life spans as the basis for demonstrating several analysis techniques the author has found useful for developing the understanding of past life span experience needed for making predictions.

This article presents the results of analyses for steam, nuclear, combustion turbine and diesel units, discusses factors that influence generating unit life spans, presents the author's interpretations of analysis results and explanations of the causes of past experience evident in the analyses, and presents analyses of the life span predictions that several utilities have proposed for depreciation accounting purposes.

Comments on Reuse Salvage Adjustments in Life and Salvage
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Mr. Bjerke reviews the article, originally written by Charles Neff in the 1998 Journal of the Society of Depreciation Professionals, and presents location life accounting procedures that will prevent the misallocation of depreciation charges.

Reconsidering Power Plant Removal Costs
Kenneth B. Powell

John Ferguson has written two earlier articles using net power plant removal cost from many utility engineering estimates to develop a cost/kw for removal cost of power plants of various types. He discusses the need for data of this type for financial accounting, regulatory accounting and economic studies.

Statistical studies show that using a simple average from the studies may overstate the removal costs for medium to large coal-fueled power plants. In addition, the relationship of cost to kw size of the plant being removed is only one of many factors that should be considered.

Price Caps and Depreciation
Don Bjerke

It is recommended that Total Factor Productivity (TFP) indices be developed in establishing price caps for specific segments of a company. The implications of developing segmented TFP indices on depreciation are discussed in this paper.

The opinions expressed in this paper are those of the author and do not reflect those of SaskTel or any other company.

Comments of John Ferguson on 1998 Journal Articles
John S. Ferguson

Mr. Ferguson provides additional discussion regarding the issues addressed by articles in the 1998 Journal of the Society of Depreciation Professionals.

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To serve as a forum for the exchange of information;

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Life Spans Of Electric Generating Units

John S. Ferguson

Abstract

Predictions of the life spans of electric generating units have been useful for numerous purposes, and the current electric industry restructuring has given such predictions added importance. An understanding of the past can be of value when attempting to predict the future. This article utilizes two sources of data on experienced generating unit life spans as the basis for demonstrating several analysis techniques the author has found useful for developing the understanding of past life span experience needed for making predictions.

This article presents the results of analyses for steam, nuclear, combustion turbine and diesel units, discusses factors that influence generating unit life spans, presents the author's interpretations of analysis results and explanations of the causes of past experience evident in the analyses, and presents analyses of the life span predictions that several utilities have proposed for depreciation accounting purposes.

Predictions of the life spans that will be experienced by electric generating units are useful for a number of purposes. My interest in the subject stems from the need to utilize expected life spans for the determination of book depreciation rates. Other uses include economic studies and generation and financial planning. Generating unit life span predictions have always been needed, but the electric industry restructuring currently in progress causes such predictions to take on added importance.

Data being maintained by the U.S. Energy Information Administration (EIA) on operating, standby (not being operated, but not retired) and retired generating units has made it easier to consider past experience when making life span predictions. However, an understanding of why the past was as it was and whether the past is a reasonable indication of the future is necessary for predictions reflecting the past to be valid. Therefore, this paper has two purposes. One purpose is to demonstrate several techniques I have found useful for analyzing data on the life spans that have been experienced by electric generating units and for evaluating the significance of such analyses. The other purpose is to present the results of my analyses. In addition, I will present my analysis of life span predictions that several utilities have proposed to utilize for depreciation accounting purposes.

PRIOR STUDIES AND SOURCES OF DATA

A depreciation-related study presented at an electric industry accounting conference in the mid-1960's found that utility boiler capacity exhibited an average life span of 45 years and the Iowa-type R4 dispersion pattern, and that utility steam turbine capacity exhibited an average life span of 50 years and the R4 dispersion pattern. A later study based on annual capacity factors, "Economic Life Span of Power Production Units," covered utility steam generating units, and was presented at an electric industry accounting conference and was published in the September 11, 1975, Public Utilities Fortnightly. A significant aspect of this study was identifying the distinctive life cycle of units. These two studies required data that were not readily available, so data collection was a major effort. Today, data availability allows generating unit life span studies to concentrate more on analyses of the past and interpretation of their significance.

The first extensive utility generating unit retirement database I became aware of was the January 1990, Utility Data Institute (UDI)

Publication UDI-005-90, "Inventory of Retired U.S. Steam-Electric Plants." I combined these UDI data as of 1988 with data on operating utility units from the Edison Electric Institute (EEI) 1990 Power Directory for analysis and evaluation purposes. Fuel type was identified, thereby allowing segregation of nuclear units from fossil units and coal and lignite units from gas and oil units. I found segregation by fuel type to be helpful for developing an understanding of the past, so repeat some of my analyses and observations herein. I presented my findings at the 1993 American Power Conference and at electric industry accounting conferences.

The UDI publication indicated that it would be periodically updated, but I do not believe it ever was. However, I have kept the nuclear experience current.

The UDI publication lists 2,291 retired utility units, but the data are sufficiently complete for the determination of the life spans for only 1,422 fossil-fired units. The 779 coal and lignite units were retired during 1943 - 1988, and the 643 gas and oil units were retired during 1960 - 1988.

The EIA now maintains data on operating, standby and retired utility generating units, and recently began to require non-utility generators (NUGs) to report such data. I have utilized EIA utility steam unit data as of 1996 and utility combustion turbine and internal combustion engine data as of 1997 to conduct analyses similar to the analyses of the UDI and EEI data I conducted several years ago. However, unlike the UDI and EEI data, I did not extract the data from EIA information, so cannot vouch for its accuracy. The EIA data utilized herein were provided by witnesses in state regulatory proceedings.

The EIA data I utilized for steam units are not segregated by fuel type, and include 1,296 retired units. The data are sufficiently complete for the determination of the experienced life spans for 1,184 retired units. However, 84 units had to be eliminated, because their indicated in-service year of 1900 is inconsistent with the timing of the commercial development of steam turbines.

The EIA data I utilized for combustion turbines and engines are segregated by fuel type, and include 117 retired combustion turbines (CTs) and 1,443 retired engines. Unlike steam units, I do not consider fuel type to be a significant influence on CT and engine life spans. However the distinction between CTs and engines is significant. While the data distinguish between three types of CTs, there is not enough retirement experience for this distinction to be meaningful. The CT and engine data include more than 200 operating units that were placed in service between 1899 and World War II (WWII), which raises a question in my mind about its accuracy.

I presented my findings for the UDI and EIA data at the 1999 International Joint Power Generation Conference, and my paper was published by the American Society of Mechanical Engineers.

The EEI and the American Gas Association provide members with an annual survey of book depreciation rates, the mortality characteristics used to calculate the rates, and several aspects of the special studies supporting the rates. While most utilities calculate their power plant depreciation rates from expected unit life spans, the survey does not collect these life spans or the estimated retirement dates from which the life spans are calculated. Therefore, the data discussed herein on life spans proposed to be utilized by utilities to calculate depreciation rates are from my own survey. My survey includes 302 fossil-steam units, 98 combustion turbines, 29 engines and nine combined cycle units, but not nuclear-steam or hydraulic units. Nuclear and hydraulic units are excluded, because depreciation rates are typically based on life spans dictated by Nuclear Regulatory Commission (NRC) operating licenses and Federal Energy Regulatory Commission (FERC) hydro project licenses.

FACTORS INFLUENCING LIFE SPAN

Both physical and non-physical factors influence generating unit life spans, so both should be considered when making predictions. Technical and operating personnel easily relate to physical factors, so tend to emphasize physical considerations when attempting to predict generating unit life spans. Non-physical considerations are at least as important, but are not as easily addressed. Data on some non-physical considerations, such as known environmental concerns, estimates of future fuel costs, unit availability and usage, and operating license authority, would likely already be available, so would require only an evaluation effort. Other non-physical considerations, such as the influences of yet to be defined environmental regulations, of alternative power sources and of a competitive power marketplace, are difficult to deal with, but are very important.

A significant aspect of dealing with non-physical considerations is recognition that the timing of the introduction of new technology can be controlled in a regulated market, but cannot be controlled in a competitive market. Therefore, the life spans experienced or expected under regulation are likely to overstate the life spans appropriate under competition.

The timing and magnitude of load growth has influenced generating unit life spans in the past. For example:

> High load growth has caused the addition of new base load units, which forced older units into the peaking mode of operation that leads to retirement. Likewise, low load growth has delayed the need for new steam units and the start of peak load operation, thereby leading to longer lives.
>
> High load relative to capacity has forced old units to stay in the base or intermediate load mode of operation, thereby leading to longer lives. Likewise, low load relative to capacity means that older less efficient units would see little, if any, operation, thereby leading to their retirement.

The influence of load growth in the future may be much different. For example, will peak load duty be met with old steam units or with new combustion turbine units? What will be the influence of an industry restructuring that may alter the obligation to serve?

How generating units are currently operated and how they will be operated in the future will significantly influence their life spans. Units providing a peaking mode of service can perform either cycling or reserve duty. Cycling duty is hard on the equipment, so can be expected to limit life, if not overcome through refurbishment. The link between life and refurbishment expenditures should be reflected in life span predictions. With appropriate maintenance, life can be extended by reserve duty in a regulated market, since the unit will rarely operate. However, such a unit would produce little or no revenue, so may not survive in a competitive market.

The current condition of the equipment and how that condition will change in the future is an obvious influence on life span. There has been considerable research into how to assess equipment condition. Many utilities have conducted assessment studies as part of efforts to extend unit life spans through refurbishment or repowering.

The future influences of factors such as these must be considered when making life span predictions. Understanding the past impact of such factors will be necessary when past experience is an aspect of life span predictions.

ANALYSES OF PAST EXPERIENCE

The remainder of this discussion relates to several types of analyses that I have found to be useful for developing an understanding of the past.

Steam Units

Figure 1 is a bubble chart of the UDI data that depicts the average age (experienced life span) and the amount of coal and lignite unit capacity retired annually during 1943 - 1988. A bubble chart allows incorporating another element of data without the complexity of a third dimension. The bubble size depicts the amount of capacity retired each year, and its center is located at the average life span that was experienced. Figure 1 shows that the majority of the reported activity was during the final 20 years and that the average experienced life span during this period was decreasing. Figure 2 is another way to look at the same data, showing a ten-year capacity weighted rolling averages of the experienced life spans, with the averages expressed as bars located at the final year of each 10-year band. The first band is 1945 - 1954, and the band rolls one year. Figures 1 and 2 demonstrate the same general pattern of average life spans. Figures 3 and 4 are the same presentations for gas and oil units. How the experience of coal and lignite units compares with the experience of gas and oil units can be helpful in developing an understanding of the past.

Figures 1 - 4 reflect only the retired units in the UDI data. Figures 5 (coal and lignite units) and 6 (gas and oil units) present actuarial or retirement rate analyses, so reflect both the retired and surviving units in the UDI data. Each curve represents the experience for the period stated at the bottom of chart. The area under each curve is the average life span experienced during the period, which are listed on Table 1 along with the shape of the survivor curve depicted by Iowa-type dispersion patterns.

Table 1

Period of Retirements	Experienced Average Life Span (years)	Iowa-Type Dispersion Pattern
Coal and Lignite Units		
1949 - 1958	35.9	L5
1959 - 1968	39.2	S4
1969 - 1978	37.1	L4
1979 - 1988	46.9	S4
Gas and Oil Units		
1959 - 1968	42.5	R5
1969 - 1978	39.4	S3
1979 - 1988	41.8	S4

The inclusion of surviving units in the analyses depicted by Figures 5 and 6 causes the patterns of life span changes to be different from the patterns depicted on Figures 1 - 4 for only retirements. Determining why including the surviving units causes this behavior is necessary for understanding the analyses on Figures 5 and 6.

Figure 7 is the equivalent of Figures 2 and 4 for the UDI data, but is for the EIA steam unit data for fuels other than nuclear. As was indicated previously, the UDI data are complete enough for only about 60 percent of the reported retirements to be incorporated into the analyses. While this is a lower percentage than the EIA retirements that were complete enough for incorporation, the EIA data are not as complete. For the period that could be compared (1955 - 1988), the amount of retired EIA capacity for which life spans could be determined is only two-thirds of the same amount of the retired UDI capacity. My evaluation of these two data sets suggests that the EIA data are sufficiently complete after 1975 to be relied upon.

Figure 8 is the equivalent of Figures 5 and 6, but for the EIA data, and its indications are summarized on Table 2.

Table 2

Period of Retirements	Experienced Average Life Span	Iowa-Type Dispersion Pattern
	years	
Coal, Lignite, Gas and Oil Units		
1967 - 1976	40.0	L4
1977 - 1986	41.8	S4
1987 - 1996	52.8	S4

Nuclear Units

The nuclear retirement activity is limited, because there are not very many nuclear units. The type of analysis depicted on Figures 5, 6 and 8 and summarized on Tables 1 and 2 shows that the average nuclear unit life span experienced during the period 1963 - 1997 was 27.8 years.

Hydraulic Units

The witness referred to earlier who collected the EIA data found that hydraulic units have exhibited an average life span of about 60 years, but concluded that the retirements were more replacement of units rather than retirement of stations. I am convinced that hydraulic stations are too unique for industry data to be meaningful, so have not included hydraulic units herein.

Combustion Turbines

Figure 9 for the EIA data is the equivalent of Figures 2, 4 and 7, and shows an increasing age of retirement. This situation is not surprising, as the technology is new, so the analysis reflects immaturity. There is not enough retirement experience for the analysis procedure that incorporates both retired and surviving units to produce meaningful results.

Internal Combustion Engines

Figure 10 for the EIA data is also the equivalent of Figures 2, 4 and 7, and shows an increasing age of retirement that is not as dramatic as for CTs. Engines are mature enough for the analysis procedure that incorporates both retired and surviving units to produce meaningful results. However, unlike Figures 5, 6 and 8 for steam units, the engine survivor curves do not reach zero. Therefore, the average life spans listed below in Table 3 are the result of fitting Iowa-type dispersion patterns to the actual survivor curves, rather than the areas under the actual curves.

Table 3

Period of Retirements	Experienced Average Life Span	Iowa-Type Dispersion Pattern
	years	
1948 - 1957	52	R3
1958 - 1967	43	R5
1968 - 1977	45	R3
1978 - 1987	36	R1.5
1988 - 1997	54	R2
1957 - 1997	50	S1
1978 - 1997	46	S0.5

Table 3 includes both a rolling 10-year band analysis and two longer periods of history, because the addition and retirement activity is too erratic for the rolling bands to be meaningful.

Life Span Predictions for Depreciation Accounting

Table 4 shows the lowest, capacity weighted average, and highest life spans that 24 utilities have recently used to calculate depreciation rates for coal, gas and oil steam units that are segregated into non-reheat, reheat and supercritical pressure categories, for internal combustion units segregated between engines and simple cycle combustion turbines units, and for combined cycle units. These life spans are calculated from the planned retirement dates of these entities.

Table 4

Type of Unit	Expected Average Life Span, years		
	Lowest	Average	Highest
Steam Units			
Non-reheat	30	52.8	81
Reheat	30	45.5	75
Supercritical	29	42.9	60
Internal Combustion Units			
Combustion Turbine	25	36.2	51
Engine	33	46.2	57
Combined Cycle Units	30	37.2	58

SIGNIFICANCE OF THE DATA AND ANALYSES

The analyses of the UDI and EIA data measure what has occurred in the past, and there is no direct link between the past and the future. However, knowledge of the past can be helpful to efforts to predict the future. Adoption of the past without a critical evaluation of its significance is not an appropriate use of the past. The UDI and EIA data do not disclose the extent, or even the existence, of life management through mode of operation, which limits the usefulness of the results of my analyses, especially for estimates of life spans in a competitive marketplace.

As was discussed previously, the UDI steam unit retirement data are more complete than the EIA data. The EIA data appear to be more complete in recent years, and my judgement is that they can be relied upon for retirements after 1975. I question the accuracy of the EIA data for combustion turbines and engines, so it is likely that their experienced life spans listed on Table 3 are overstated.

The life spans utilized for depreciation purposes are predictions of the future.

Accounting Implications

Mode of operation often produces a distinctive life cycle that is of significance to depreciation accounting, because of the generally accepted accounting principle that depreciation accounting be both "systematic and rational." "Rational" means that the pattern of recording depreciation should match the pattern of the usage of the underlying assets.

Steam generating units have commonly been installed to initially function in a base load mode of operation, and most retired fossil-fired steam units have operated in a cycling or reserve mode late in life. Complying with accounting principles means that generating units expected to have such a distinctive life cycle should have higher depreciation rates in their early years of life than in later years. Units for which life is extended by reserve duty should be fully depreciated by the time reserve duty begins, because revenue generation will have ceased.

The lower life spans demonstrated for depreciation purposes for reheat and supercritical units are consistent with the status of efforts to extend life through refurbishment or repowering, and with the need to match the cause of life extension (refurbishment or repowering expenditures) with the effects of the expenditures (life extension). The non-reheat, reheat and combustion turbine units exhibit trends to lower life spans for newer units that are consistent with the need to match capital expenditures for component addition and replacement to the resulting life spans, and for steam units that are consistent with their typical distinctive life cycle. However, regulation usually precludes the cause and effect matching to be as complete as accounting principles call for, so the indicated life spans are likely longer and the trends less dramatic than would be used for the same purpose if the entities were not regulated.

The importance of having an understanding of the data will be evident from the following discussions of the significance of these analyses.

Influence of Life Management

The distinctive generating unit life cycle is a form of life management, whereby a unit has its life extended beyond what would occur if it is not capable of operating in a peaking mode late in life. This form of life extension has affected many steam units. Fuel cycle economics, NRC licensing and the politics of nuclear power are likely to keep nuclear units from operating in a peaking mode late in life, and may preclude their operating as long as operating licenses would allow. How hydraulic units operate is dictated by water supply. Combustion turbines and engines typically operate in the same mode throughout their lifetimes.

In the late 1960's, coal and lignite units began to require significant investments to comply with newly enacted environmental regulations. These investments allowed such units to reach their planned lifetimes, but some were removed from service because the expenditures could not be justified. This situation continues, as environmental regulations are periodically made more stringent. The scrubbers utilized to meet environmental regulations are essentially chemical plants that require stable operation to produce the desired product. Therefore, units that require scrubbers cannot be expected to have their lives extended through cycling duty. Supercritical pressure units have operating characteristics that may preclude extending their life spans through cycling duty.

In the mid-1980's, utilities began to embark upon refurbishment and repowering projects intended to extend life spans of steam units beyond the 40 - 45 years typically experienced in the past and beyond the 20 - 25 years typically expected for combustion turbine units. These projects are more extensive than the normal refurbishment that is required to respond to the increase in forced outages that typically starts at an age of about 20 years.

Some utilities recently began to sell their generating units in response to the electric industry restructuring. While some sales have been mandated, many are by sellers who have concluded that the units are too costly for a competitive marketplace. However, purchasers are paying more than book value for many of the steam units, suggesting they are more interested in the sites than in the existing facilities. Therefore, early retirement is likely for some units, and revenue considerations suggest that it is unlikely that life would be extended by reserve duty in a competitive market. Regulated entities that have not put their power plants up for sale have reacted to the industry restructuring in two ways. One reaction has been to purchase rather than build to meet base load needs, which may increase the life spans of existing units. The other reaction has been to adopt the approach of NUGs – build gas-fired combustion turbine and combined cycle units. Replacing the peaking function that old steam units have performed in the past with combustion turbines will eliminate the potential for the operational mode of life extension, but some of the lost life span may be offset through refurbishment that would not otherwise take place.

As is evident from this discussion, these forms of life management have influenced the past. All remain in place. The influence of industry restructuring will be the most difficult to deal with, because looking at a regulated past will be of little help.

Interpretation of Analysis Results for Steam Units

The analyses on Tables 1 and 2 show similar dispersion patterns that are also similar to the patterns found by the 1960's study of boiler and turbine capacity. These analyses disclose relatively narrow patterns that indicate limited life span variation from the averages.

Table 1 shows generally similar average life spans for the two UDI data fuel categories, but somewhat different trends. Fuel conversion may have caused gas and oil unit life spans to be higher than otherwise, but the UDI and EEI publications do not disclose fuel conversions, except to the extent that coal listed as a secondary fuel suggests that fuel conversion has taken place. Such units were classified as coal units for these analyses.

Table 2 shows a pattern of life span changes for the EIA data different from those on Table 1 for the UDI data. The 1967 - 1976 EIA data life span is about two years higher than for the UDI data, suggesting the influence of incomplete data. I do not have sufficient detail for the EIA data to explain the higher life span for the period 1977 - 1986, during which the data seem complete. The EIA data life span increase during 1987 - 1996 is larger than would be expected from the pattern of retirement ages on Figure 7, indicating the increase is due to older surviving capacity rather than to older retired capacity. This situation is consistent with utility efforts to extend life through refurbishment or repowering, rather than by building new units.

Most of the retired steam units incorporated into my analyses have had their lives extended by operating in a peak load mode late in life, so the analyses presented herein will be of value for predicting total life spans of units that will so operate. However, existing units and new units may not be operated in the same manner. My experience indicates that the final ten years or so of the experienced steam unit life spans were spent in a cycling or reserve mode, prior to when life extension came to be preferred over new construction. Therefore, deducting ten years from the total life spans experienced prior to the mid-1980's may be a reasonable approximation of the life spent by steam units in base and intermediate load operation. This recognition has always been useful for determining depreciation rates that are consistent with accounting principles, and takes on even more importance for dealing with the influence of the changing marketplace.

The EEI Power Directory and the EIA data include a number of steam units in a standby mode that were not incorporated into these analyses. I am aware that a few of the retired units were placed in a standby mode prior to retirement, but UDI does not disclose whether reported retirement dates are the dates of placement in standby service or dates of final retirement. I did not collect the EIA data, so do not know which date is represented either. There were only a few such units prior to 1988, so they had little influence on my analyses of the UDI data. However, the units then in a standby mode would influence future analyses, such as of the EIA data, since their total life spans will be longer than their operating life spans. I am also aware that several utilities have more recently reacted to lower than expected load growth by moving units to standby service and bringing them back when load caught up with capacity. The EIA data include 2,049 surviving steam units, of which 1,910 are operating and included in my analyses and 139 are standby units that I have excluded. The standby units amount to 12 percent of the retired units and 24 percent of the retired capacity, so will be of significance to future analyses of EIA data.

Developing an understanding of the data underlying any analysis should be one of the steps in the process of evaluating the significance of the analysis. For example, the average size of the retired coal and lignite units (22 MW) in the UDI data is only 9 percent of the average size of the units surviving at the end of 1988 (238 MW). The average size of the units surviving at the end of 1996 in the EIA data is nearly the same (235 MW), and the average size of the retired units is 30 MW. Further, many of the retired steam units were installed prior to WWII. Generating unit sizes, designs, materials and operating conditions were much different after WWII than prior to WWII. Evaluation of the significance of this history must include the determination of whether the life spans experienced by pre-WWII steam units are predictive of the life spans of modern units.

It is clear that many of the non-reheat units in the depreciation data have had their expected life spans increased by some form of life extension. I am aware that nearly 25% of the units have been life extended through refurbishment or repowering or are candidates for life extension, and there are probably more such units. However, I would expect the most common mode of life extension of non-reheat units to be operational.

Nearly 20% of the reheat units in the depreciation data have been life extended through refurbishment or are candidates for life extension, and there are probably more such units. I am aware that the expected life spans used for some of these units reflect the expectation without life extension, in order to keep the depreciation rates from an initial large decrease followed by a large increase when the expected life extension is accomplished. It is probably safe to assume that life spans less than the average of 45.5 years do not reflect life extension, and that life spans more than the average do reflect life extension.

While several of the supercritical units in the depreciation data are known candidates for life extension, I am aware of only one that has already been refurbished. However, 10% of the units have been life extended through fuel conversion and scrubber installation. The meaning of life spans below and above the average is probably the same as for reheat units. Operating characteristics of supercritical pressure units may preclude the operational mode of life extension.

Interpretation of Analysis Results for Nuclear Units

It is not surprising that the nuclear unit life span experience of 27.8 years is less than the 40-year term of NRC operating licenses, because the expenditures needed to keep a unit operating become less viable as the end of life approaches. The NRC has issued rules and regulatory guidance that would allow issuing a new operating license having a termination date up to 20 years beyond the termination date of the original license. It seems clear that relicensing will be required for nuclear units to reach their existing license termination dates. This past experience suggests that operating to the termination date of the original license is consistent with a 50% probability of receiving a new license for the allowable 20-year extension. The first two relicensing requests were recently filed. However, if relicensing becomes as political as the original licensing, relicensing will not take place.

Interpretation of Analysis Results for Combustion Turbines

There is not enough experience to draw any conclusions from the past retirement experience in the EIA data. Unlike steam units, there is not a lot of size difference between retired units (21 MW) and surviving units (41 MW). However, there has been considerable technological development. Heat rates have decreased significantly, materials and designs are more exotic, and operating temperatures have increased. Therefore, evaluation of the significance of the past must include the determination of whether the life spans experienced by older CTs will be predictive of the life spans of modern units subject to more severe duty.

The EIA data utilized herein do not distinguish between simple-cycle CT's and CT's in combined-cycle service. Simple-cycle units are likely to function in a cycling or reserve mode throughout their lifetimes, and combined-cycle units will be based loaded. Therefore, the factors that influence retirement will be different. Past experience for simple-cycle units cannot be expected to be meaningful for combined-cycle units, and vise versa. Some simple-cycle units serve black-start or area protection functions, so are influenced by how long these functions are needed, and are sufficiently portable to move if still operable after the original need ceases. A future complication will arise if the current plans of some entities to buy CTs for intermediate load duty are fulfilled.

Of the 11 units the depreciation data indicate are expected to have life spans of 50 years or more, nine have been refurbished to extend their life spans by 20 years and one was installed to burn sour gas that did not justify cleaning up at the then existing prices. These ten units are too small to influence the average. However, it seems clear that getting beyond a life span of 25 - 30 years will require some form of life extension. I am aware that about 10% of the CTs serve a black-start function, so take on the life of the power plant served, and there may be more black-start units than I know about. The expected life spans for black-start units range from 39 to 46 years, and influence the average.

Interpretation of Analysis Results for Engines

There is no size difference between retired units and surviving units in the EIA data, and technological developments have been much less dramatic than for other types of units. However, pre-WWII engines are likely to be low speed units that have been subject to less severe operating conditions than have the post-WWII engines likely to be high speed.

Some pre-WWII units may have initially served a base load function, so may have had their lives extended by shifting to a reserve function. Post-WWII units are likely to have been installed to serve a reserve function and never changed. Like simple-cycle CTs, engines can also serve black-start or area protection functions, and modern units are portable.

The average life span utilized for depreciation purposes is nearly identical to the historical indications of the past 20 years. The depreciation data reflects units that are mostly utilized for area protection, black-start or black-shutdown purposes, so tend to take on the life of the power plant or area protection needs.

Interpretation of Analysis Results for Combined Cycle Units

Only the life spans for depreciation purposes segregate combined cycle units. Of the four units expected to have life spans over 34 years:

> Two are the steam and CT units of a combined cycle unit having supplemental boiler firing, so take the expected life of the steam unit;
>
> One is a steam unit that was once retired and then brought back into service with new CTs and waste heat boilers; and,
>
> One is an industrial type CT serving an inlet air pre-heating role, and was moved to a newer steam unit upon the retirement of the original unit.

Therefore, the average life span may not be a reasonable indication of what can be expected for modern units.

Historical Perspective

The wide range of circumstances and lack of past experience details make it impossible to determine if the past conditions are comparable to the expected future conditions. Therefore, analyses such as those herein do not provide a sound basis for judging the validity of planned retirement dates of the generating units of an individual utility or about what is appropriate for an individual generating unit. However, analyses such as these are useful for developing an understanding of what has occurred in the past that can enhance the validity of predictions. Therefore, the remainder of this discussion attempts to explain the past that is depicted by my analyses of UDI and EIA data.

Figures 11 (UDI coal and lignite units), 12 (UDI gas and oil units) and 13 (EIA steam units) show annual capacity additions and retirements expressed as ratios of installed capacity at the beginning of the year. I have found this type of analysis useful for developing an understanding of the past, as the answers to the questions it often raises are helpful for explaining the past. The Figures are plotted to the same vertical scale to make them comparable, and the retirements are multiplied by ten to make their patterns visible. The amount of steam capacity retired prior to the mid-1960's is too low to make the pre-1960 retirement experience very meaningful. The low retirements may be more of an indication of an incomplete retirement data base than of low actual retirements.

The patterns of capacity addition and retirement ratios on Figures 11 and 12 are obviously different, particularly the retirements. The influence of environmental protection regulations is evident from the 1969 - 1975 increase in coal and lignite retirements, which causes the trends shown on Table 1. The need to meet more stringent environmental rules caused premature retirements and some fuel conversions of coal units, decreasing the average life span for 1969 - 1978 relative to the other periods.

Gas and oil units also show higher retirement ratios beginning in the late 1960's, but coal and lignite unit retirement ratios were low in the 1980's, while gas and oil units exhibited even higher retirement ratios in the 1980's than previously. I doubt that any gas and oil units have been retired for environmental purposes. However, the UDI gas and oil unit retirement data likely include some coal units that were converted to oil just in time for the oil price fly-up due to the 1973 oil embargo. Such units were likely retired during the 1970's. The gas and oil unit retirement ratio increase in the 1970's and beyond is likely due to high fuel costs and decreased load growth.

A factor contributing to the high gas and oil unit retirement ratios in the 1980's is the lack of installations of such units by utilities. The gas and oil unit installed capacity decreased after 1973, I believe due to high fuel costs and limitations imposed in the late 1970's on the use of gas for electric generation. This situation has since changed, as the prohibitions of the use of gas by the Texas Railroad Commission and by the Powerplant and Industrial Fuel Use Act were repealed, numerous NUGs have placed gas-fired units in service, and some utilities have eliminated coal and lignite from their planning. The life spans of NUG gas units are likely to be shorter than the experience shown by these analyses, because they may not be economically viable in a peaking mode of operation. Another factor contributing to the high gas and oil unit retirement ratios in the mid-1980's is the excess capacity situation that began after the 1973 oil embargo, as high fuel costs made such units vulnerable to retirement. I once thought that future circumstances are unlikely to emulate the upheavals from the oil embargo. However, the massive 1990's shift to gas as the preferred generating fuel might create enough demand to cause future gas prices to affect gas unit life spans in a similar manner.

Not having the EIA steam unit data segregated by fuel type limits its usefulness. However, it is clear that the dearth of recent utility additions evident in the UDI data has continued. It would be helpful to know the fuels involved in the increased retirements after 1990 shown on Figure 13.

The addition ratio decreases beyond 1975 demonstrated on Figure 12 for gas and oil units and on Figure 13 for the EIA data are significant to interpreting the type of analysis shown by Figures 5, 6 and 8 and summarized on Tables 1 and 2. The ratio decreases show that the capacity is not being replaced in kind, thereby indicating dying asset groups. A dying group typically exhibits increasing life, which is evident from my analyses, and exhibits an increasing range of variation around the average life, which is evident for the gas and oil units but not for the EIA data. The most significant aspect of this situation is that capacity is being replaced, but not by utility steam units. Therefore, looking only at utility steam units does not provide a complete picture of the experience. A further complication is that the current electric industry restructuring involves the sale of power plants by some utilities. The types of analyses presented herein are likely to be misleading in the future, if limited to only utility ownership. The most meaningful analyses will follow the generating units, regardless of ownership.

Figures 14 (CTs) and 15 (engines) show their patterns of additions and retirements. The influence of the 1965 northeast blackout is clear on Figure 14, but the limited use of CTs for electric generation prior to 1965 limits the usefulness of the illustrated addition and retirement patterns. The patterns are influenced by the increase in installed capacity making up the denominators of the ratios. For example, the magnitude of the CT capacity additions in the last ten years, when CTs were being installed instead of steam units, is hidden as a result of the installed capacity in 1990 being about 40 times that in 1965. This situation is reflected to some extent in some of the other ratio charts herein, which should be recognized when evaluating the significance of the disclosed patterns.

The typical post-WWII utility service provided by engines and simple-cycle combustion turbines has been for peaking. The life span influence of cycling and reserve duty probably does not vary by unit type. Utility experience or expectations for internal combustion units will be of little use to those estimating life spans of any such units providing base or intermediate load service.

CONCLUSION

The analysis techniques presented and discussed herein provide clues to the impact of past conditions on the life spans of electric generating units, so can be helpful in developing an understanding of history that is useful for predicting the future. While not demonstrated by these analyses, I believe that the average life span for fossil-fired steam units reaching a peak load mode of operation without life extension has been 30 - 40 years. The low end of this range is consistent with when published data on forced outage rates indicates that continued operation would require life extension through refurbishment, repowering, or shifting to a peaking mode of service. Life extension by these means has particular significance to depreciation, as utility regulators typically require that these conditions be reflected for regulatory purposes in a manner that defers the recording of depreciation, and will be of particular significance to those making life span predictions in a competitive market place.

The extensive efforts of utilities to extend life spans of steam units through refurbishment and repowering indicate that analyses such as these are becoming unreliable indicators of when units can be expected to shift to a peaking status. Analyses such as these are also becoming an unreliable indicator of total future life spans, because:

Steam units not already in a peaking mode of operation may never reach it, because combustion turbines will replace existing steam units used for peaking;

Environmental considerations may cause another wave of early retirements;

The rush to gas-fired units may be only an interim solution to capacity and environmental needs;

Utility units in the reserve mode of operation are more likely to be retired than to be operated after purchase by a non-regulated entity;

Non-utility generating units may not have their lives extended by mode of operation; and,

The lives of nuclear units will be dictated by political considerations that are not possible to predict.

I once would have included the 1973 oil embargo as an unreliable indicator. However, the massive shift to gas as the preferred generating fuel might cause future gas prices to influence gas unit life spans in a manner similar to the oil embargo.

It is clear that analyses such as these do not provide a basis for evaluating the plans of an individual utility or non-regulated generator or for evaluating what is appropriate for individual generating units, because it is impossible to segregate the data sufficiently for comparability. This situation means that analysts must relate specifically to the generating units in question to determine or evaluate the plans of an individual utility or non-regulated generator.

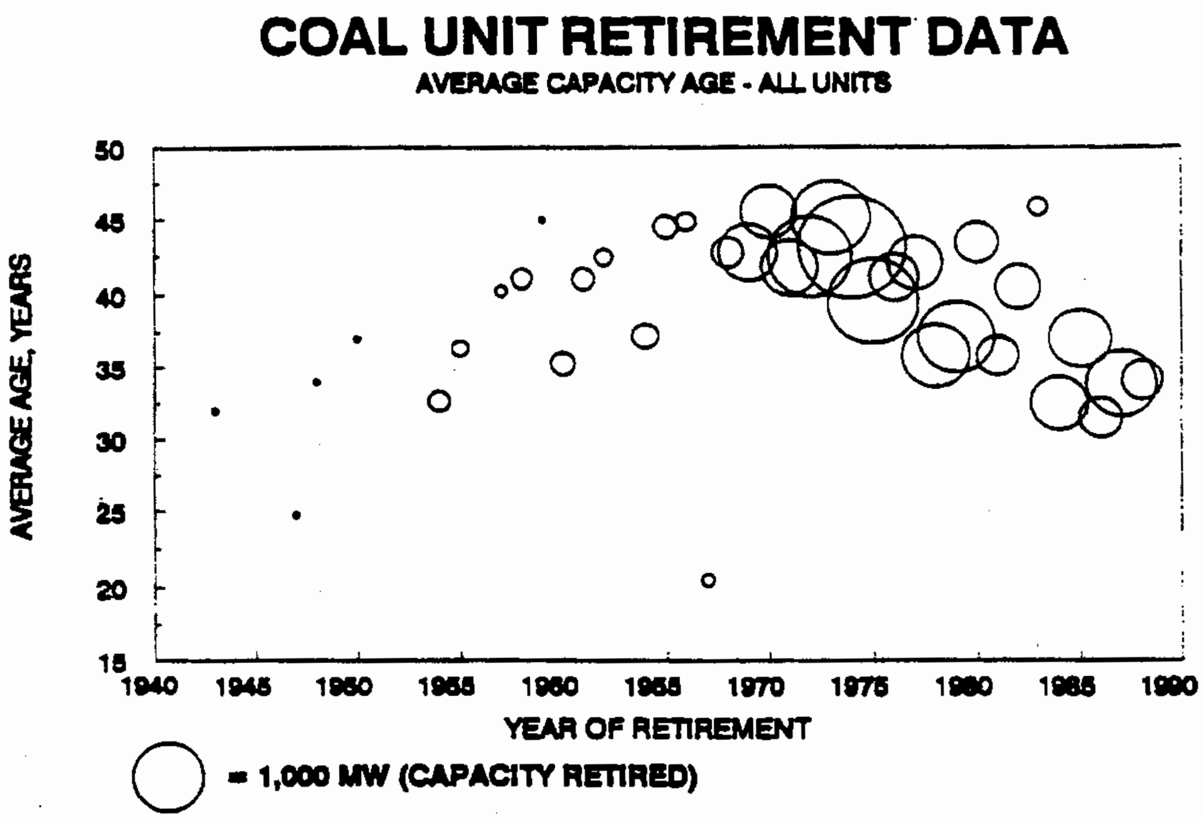
COAL UNIT RETIREMENT DATA
AVERAGE CAPACITY AGE - ALL UNITS
AVERAGE AGE, YEARS
YEAR OF RETIREMENT
= 1,000 MW (CAPACITY RETIRED)

Fig. 1

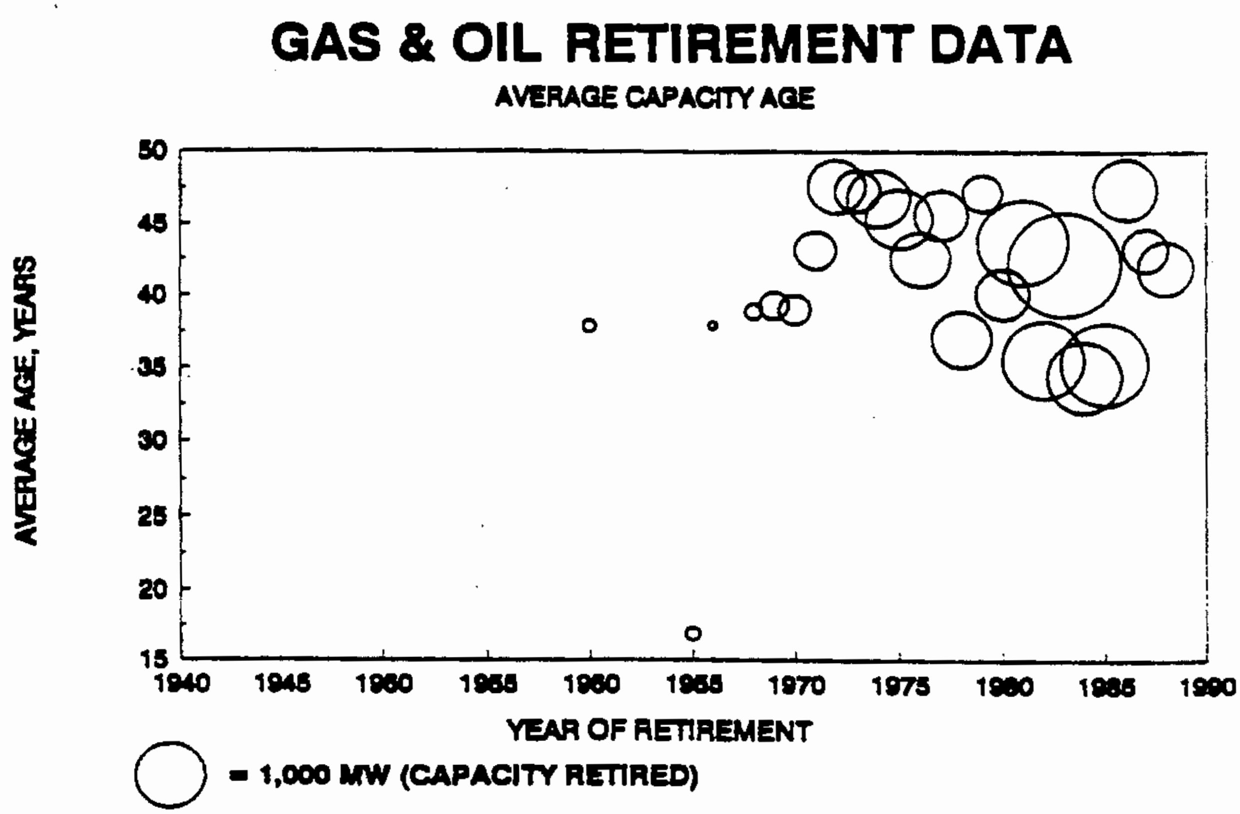
GAS & OIL RETIREMENT DATA
AVERAGE CAPACITY AGE
AVERAGE AGE, YEARS
YEAR OF RETIREMENT
= 1,000 MW (CAPACITY RETIRED)

Fig. 3

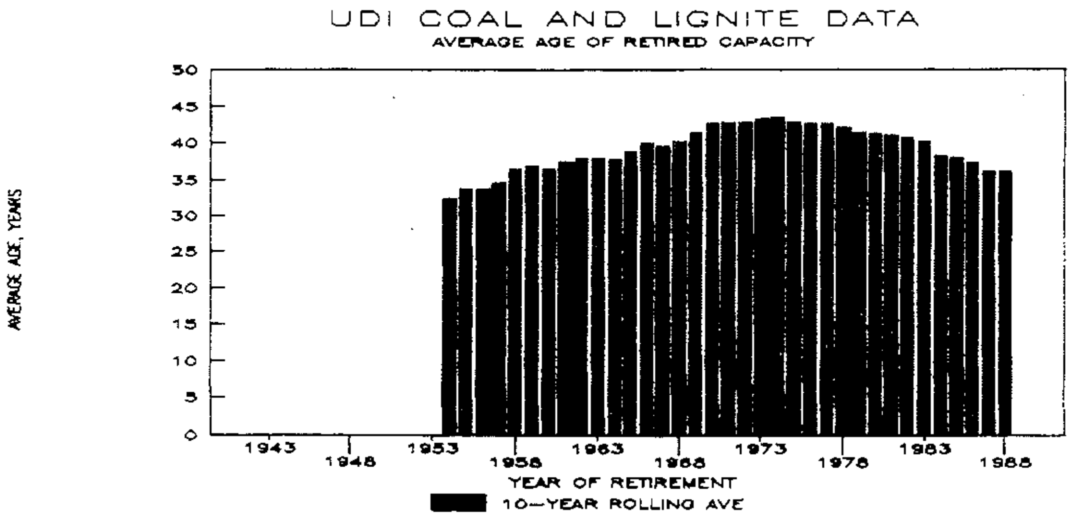

Fig. 2

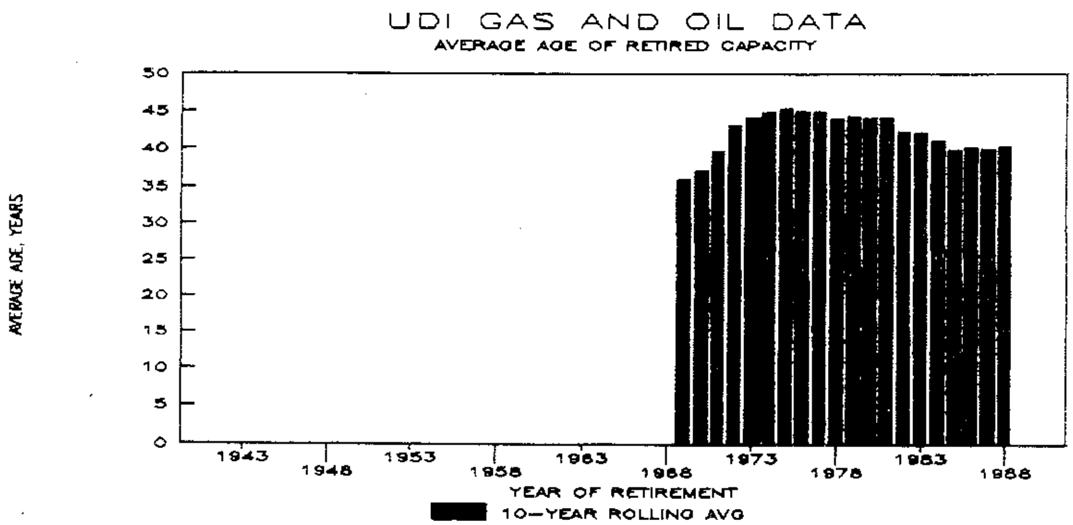

Fig. 4

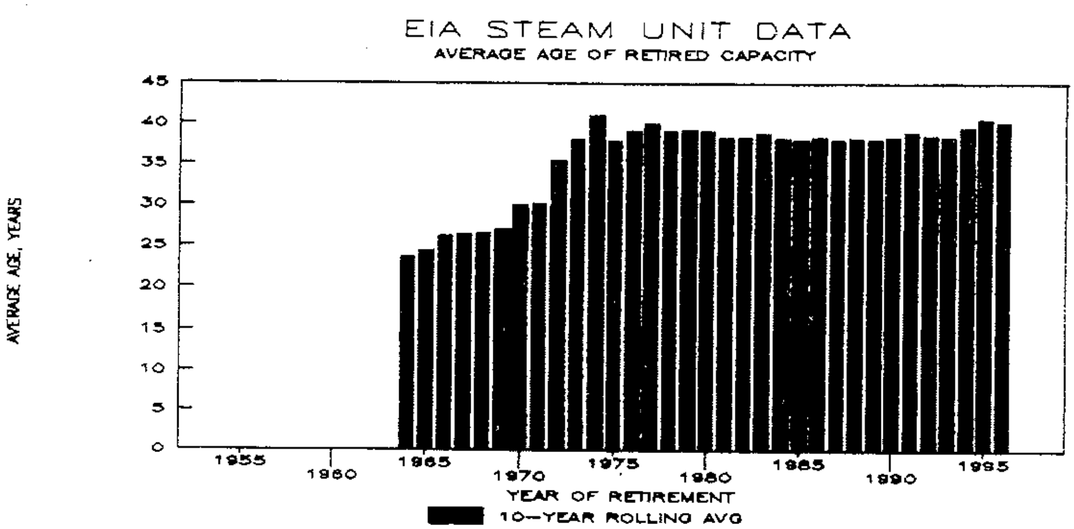

Fig. 7

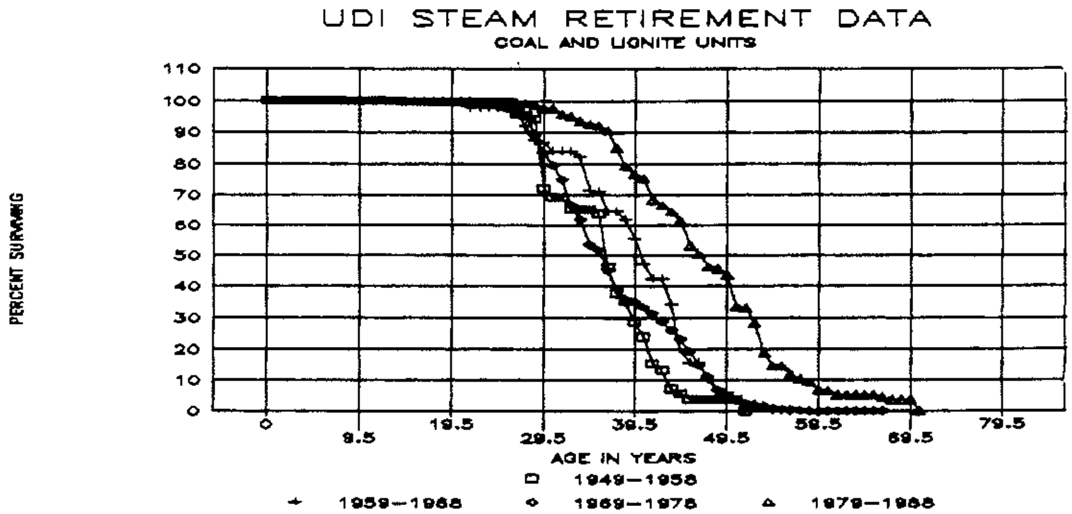

Fig. 5

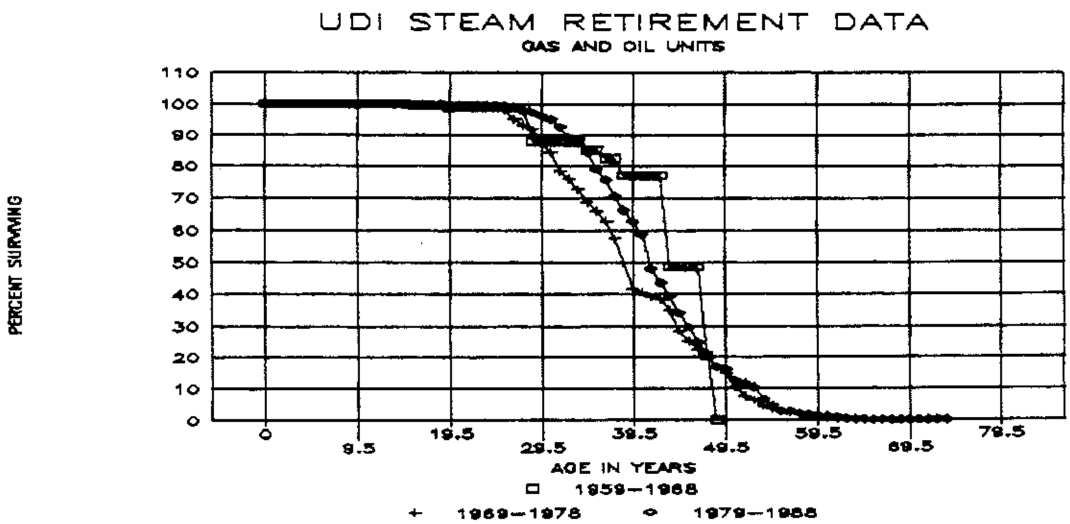

Fig. 6

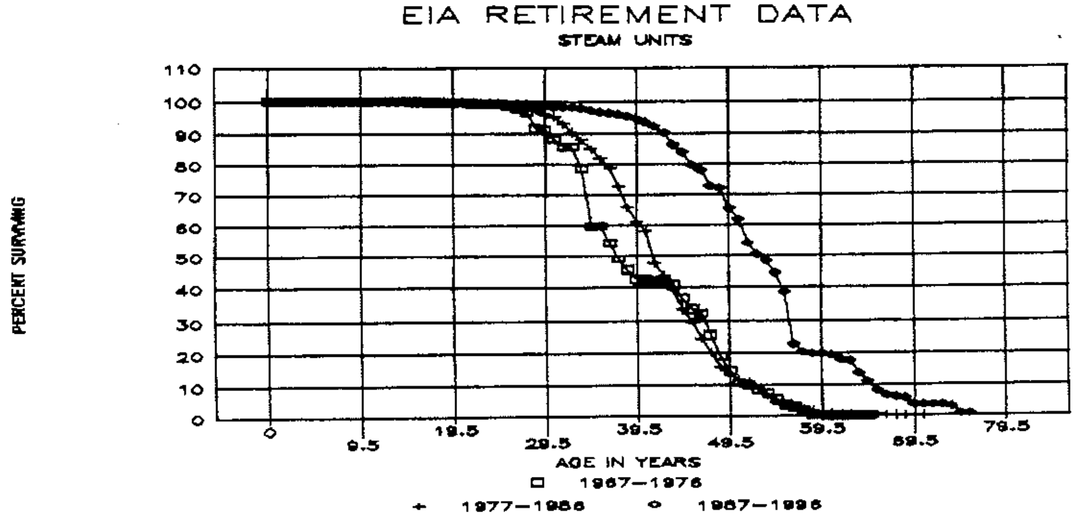

Fig. 8

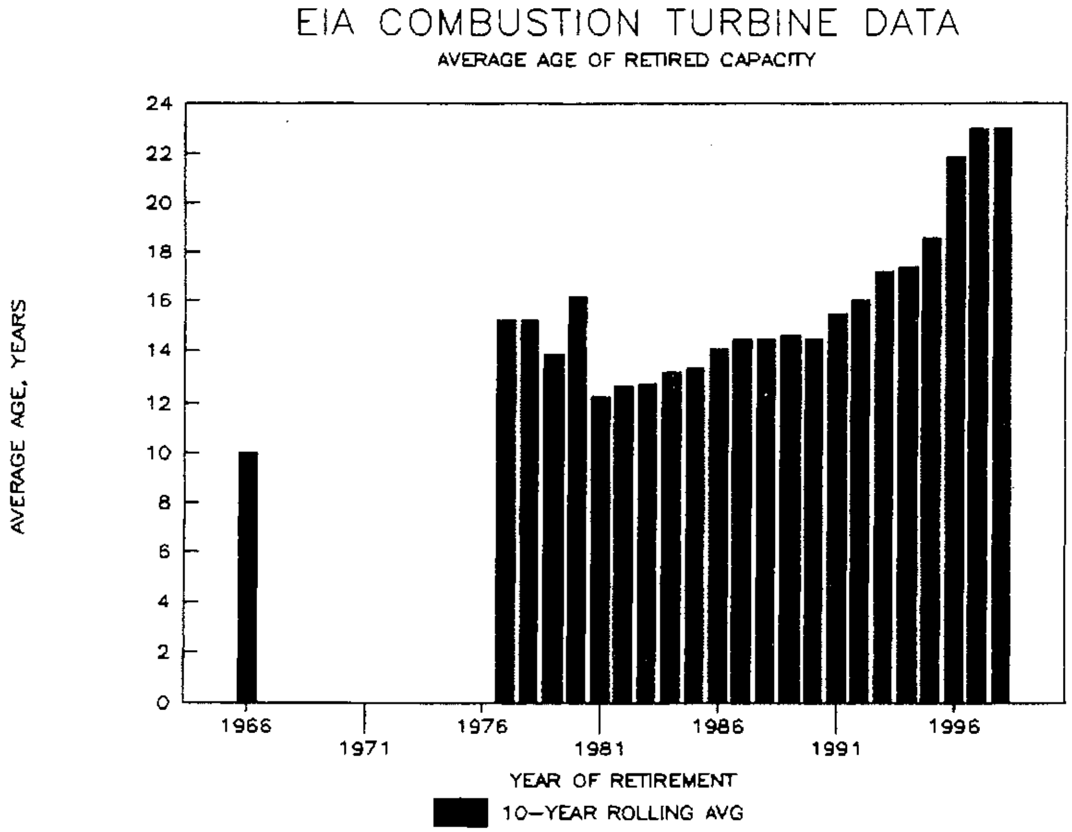
EIA COMBUSTION TURBINE DATA
AVERAGE AGE OF RETIRED CAPACITY
AVERAGE AGE, YEARS
0
2
4
6
8
10
12
14
16
18
20
22
24
1966
1971
1976
1981
1986
1991
1996
YEAR OF RETIREMENT
10–YEAR ROLLING AVG

Fig. 9

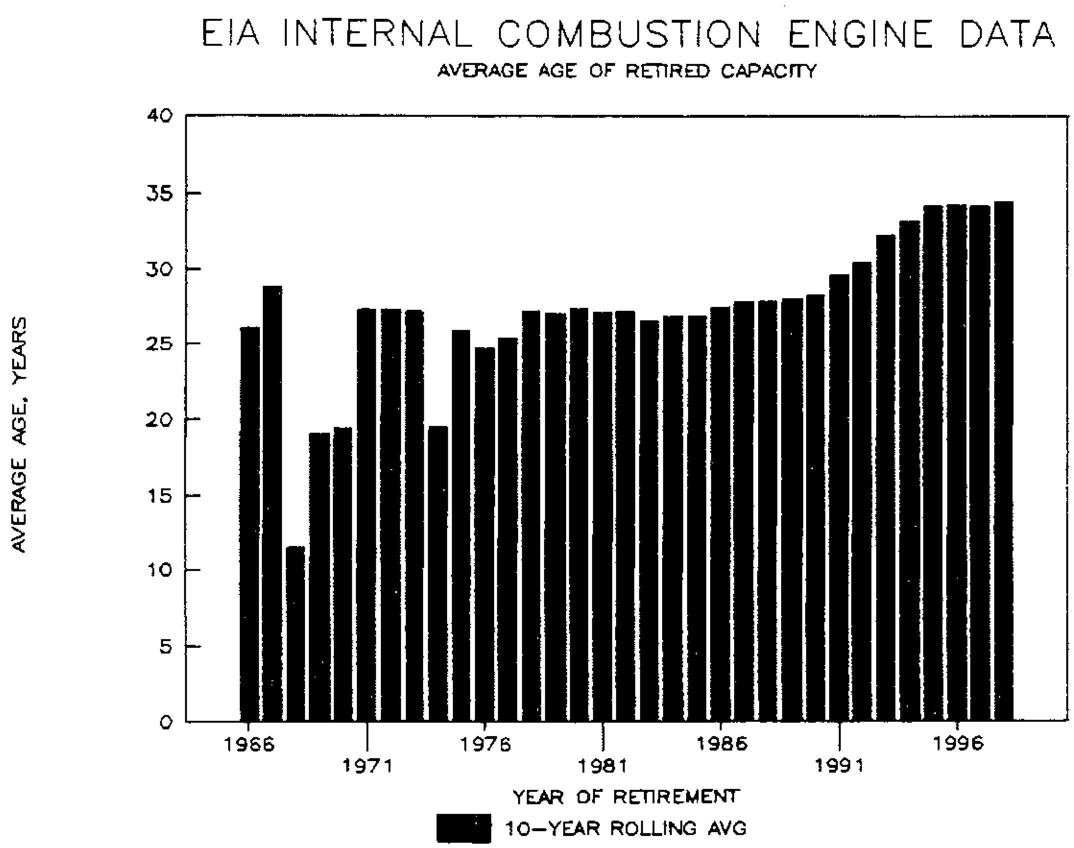
EIA INTERNAL COMBUSTION ENGINE DATA
AVERAGE AGE OF RETIRED CAPACITY
AVERAGE AGE, YEARS
0
5
10
15
20
25
30
35
40
1966
1971
1976
1981
1986
1991
1996
YEAR OF RETIREMENT
10–YEAR ROLLING AVG

Fig. 10

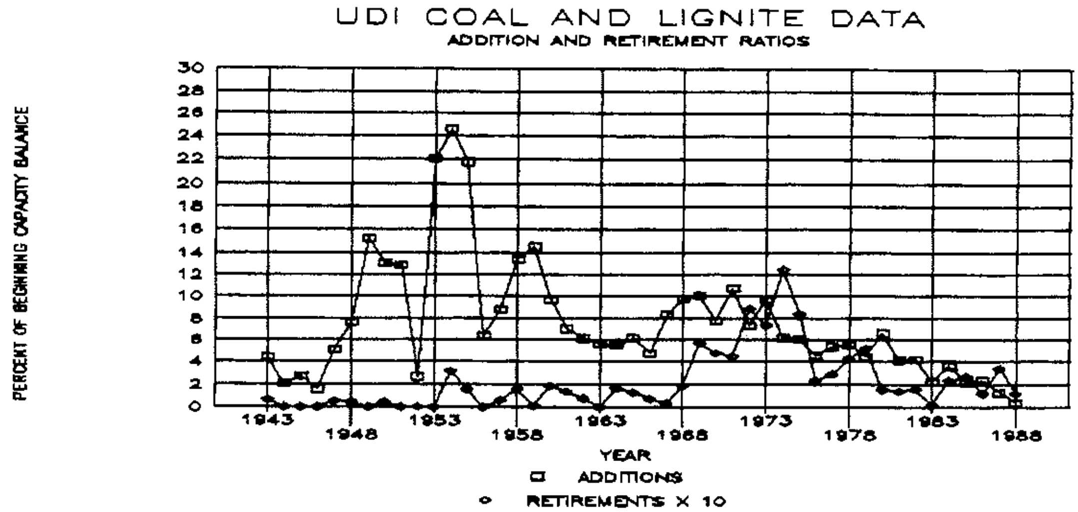

Fig. 11

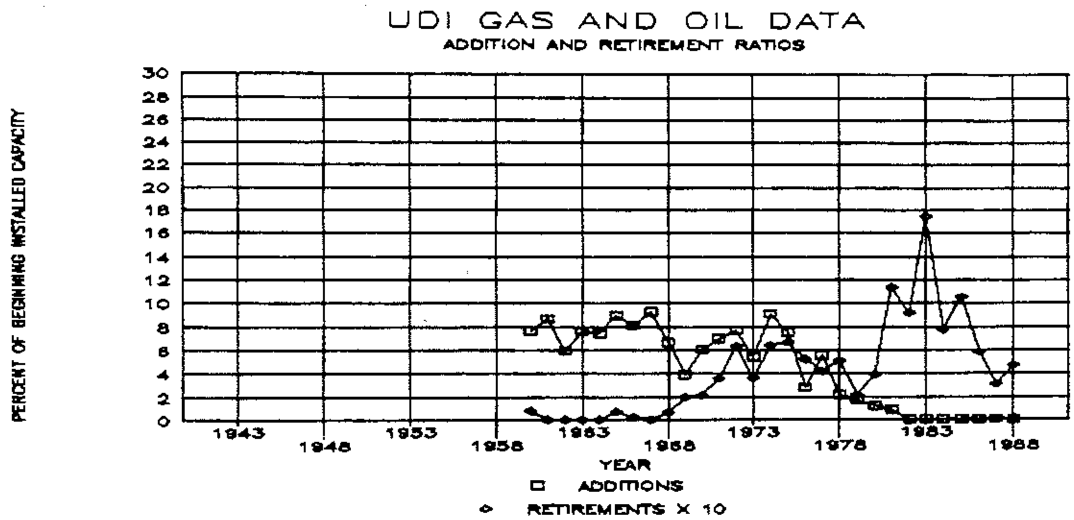

Fig. 12

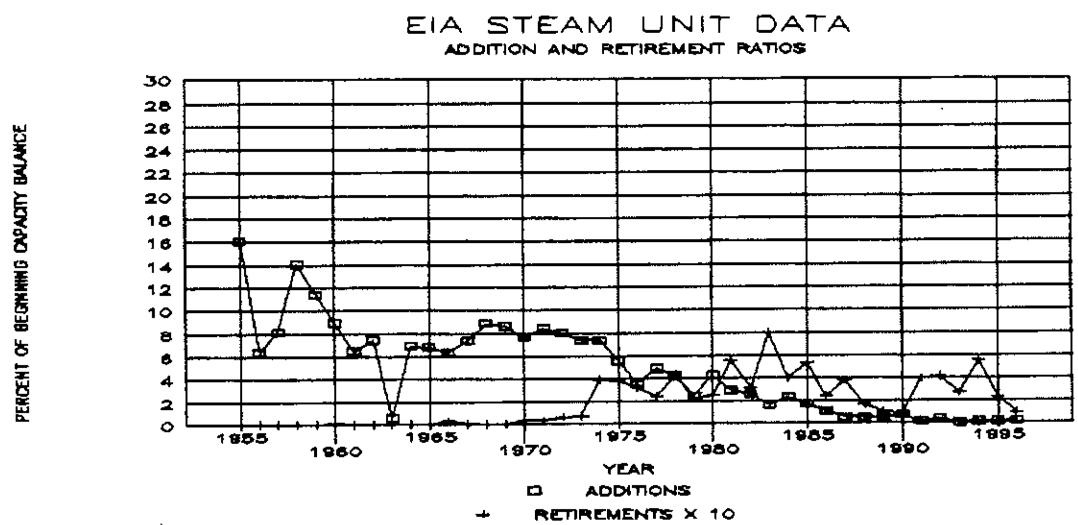

Fig. 13

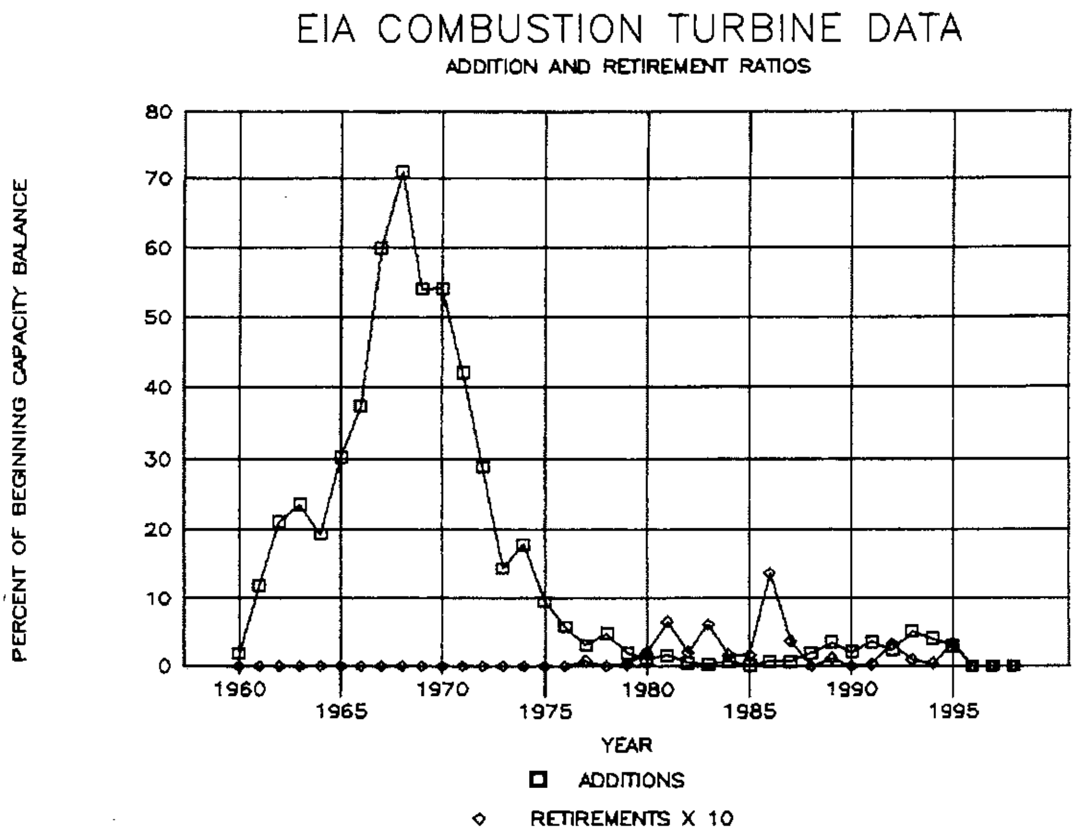
EIA COMBUSTION TURBINE DATA
ADDITION AND RETIREMENT RATIOS
PERCENT OF BEGINNING CAPACITY BALANCE
0
10
20
30
40
50
60
70
80
1960
1965
1970
1975
1980
1985
1990
1995
YEAR
ADDITIONS
RETIREMENTS X 10

Fig. 14

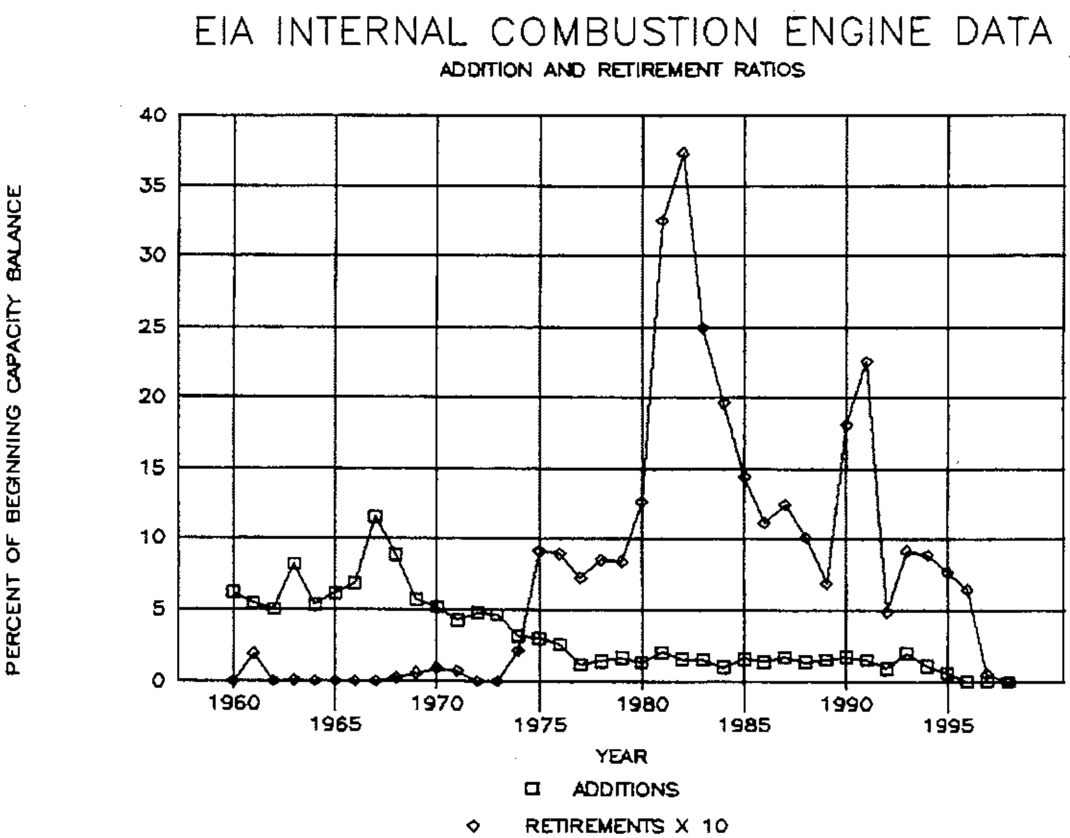
EIA INTERNAL COMBUSTION ENGINE DATA
ADDITION AND RETIREMENT RATIOS
PERCENT OF BEGINNING CAPACITY BALANCE
0
5
10
15
20
25
30
35
40
1960
1965
1970
1975
1980
1985
1990
1995
YEAR
ADDITIONS
RETIREMENTS X 10

Fig. 15

Comments On Reuse Salvage Adjustments In Life And Salvage Estimation

Ralph Bjerke

Charles P. Neff, in his article that was published in the 1998 Journal, illustrates how a reversal in reused material can correct the misallocation of depreciation charges over the life of an asset. The simple fact that an adjustment is required at all would indicate that there must be something wrong with the traditional location life accounting entries. Would it not make more sense to use the correct accounting procedures in the first place and thus avoid these adjustments? In order to accomplish this, certain modifications have to be made to both the field and inventory accounting systems:

Current Inventory

All inventory items must be segregated into new and used stock with the new items being purchased into a current inventory. From here, these items can either be sold or issued into the field where they will be capitalized. An average weighted original cost is usually maintained for each type of item. Larger items may be purchased and issued directly into the field, thereby bypassing current inventory, but these must also be included as gross additions.

Field Investment

The traditional location accounting entries describe the transactions that occur in the field and these must be modified as follows:

> All new items issued into the field must be capitalized.
>
> If items can potentially be reused, they should be returned to a capital inventory. All transfers of used issues and returns from the field are recorded at their original cost.
>
> Items that are beyond economic repair should be junked in the field and recorded as a final retirement. This is a credit to the field investment account and a debit to accumulated depreciation.

Capital Inventory

Capital inventory can be thought of as just another location where used items can be repaired but still continue to depreciate. They do not, however, generate revenues.

> New items are not purchased into capital inventory.
>
> All transfers of used issues and returns from capital inventory are recorded at their original cost.
>
> Items that are beyond economic repair should be junked from capital inventory and recorded as a final retirement. This is a credit to capital inventory and a debit to accumulated depreciation.

When the above transactions for field and capital inventory are combined:

> represents all new items being issued into the field;
>
> cancels out; and,
>
> represents all final retirements.

This consolidation is represented by the shaded area in Figure 1.

Although the movement of items is recorded on a location basis, the summation of the field investment with capital inventory represents cradle-to-grave accounting concepts.
The accounting entries are shown in Table 1 and produce the same balances as shown in Mr. Neff's Table 3 "Depreciation Expense Adjusted for Reuse". The depreciable plant shown in Table 1 also matches Mr. Neff's Figure 2 "Survivor Curve Adjusted for Reuse". The Canadian Radio-television and Telecommunications Commission (CRTC) has long recognized this problem with traditional location life accounting procedures and has issued directive 10 which states that:

"*The original installed cost of all depreciable plant shall be depreciated over its entire useful life, regardless of any relocation.*"

TABLE 1 – Modified Location Life Accounting Entries

	Year		
	1	2	3
FIELD INVESTMENT			
Opening Balance (Jan 1st)	0.00	500.00	0.00
Purchases Issued to the Field	1,000.00	0.00	0.00
Net of Used Issues and Returns	-50.00	-50.00	0.00
Final Retirements from Field	-450.00	-450.00	0.00
Closing Balance (Dec. 31st)	500.00	0.00	0.00
CAPITAL INVENTORY			
Opening Balance (Jan 1st)	0.00	50.00	100.00
Net of Used Issues and Returns	50.00	50.00	0.00
Final Retirements from Capital Inventory	0.00	0.00	-100.00
Closing Balance (Dec 31st)	50.00	100.00	0.00
FIELD + CAPITAL INVENTORY			
Opening Balance (Jan 1st)	0.00	550.00	100.00
Gross Additions (new)	1,000.00	0.00	0.00
Net of Used Issues and Returns	0.00	0.00	0.00
Final Retirements	-450.00	-450.00	-100.0
Closing Balance (Dec 31st)	550.00	100.00	0.00
ACCUMULATED DEPRECIATION			
Opening balance (Jan 1st)	0.00	187.27	47.27
Depreciation	727.27	400.00	72.73
Final Retirements	-450.00	-450.00	-100.00
Cost of Removal	-90.00	-90.00	-20.00
Closing Balance (Dec 31st)	187.27	47.27	-0.00
NET BOOK VALUE			
Field + Capital Inventory (Dec 31st)	550.00	100.00	0.00
Accumulated Depreciation (Dec 31st)	-187.27	-47.27	0.00
Net Book Value (Dec 31st)	362.73	52.73	0.00

Reconsidering Power Plant Removal Costs

Kenneth B. Powell

Abstract

John Ferguson has written two earlier articles using net power plant removal cost from many utility engineering estimates to develop a cost/kw for removal cost of power plants of various types. He discusses the need for data of this type for financial accounting, regulatory accounting and economic studies.

Statistical studies show that using a simple average from the studies may overstate the removal costs for medium to large coal-fueled power plants. In addition, the relationship of cost to kw size of the plant being removed is only one of many factors that should be considered.

John Ferguson has provided two articles discussing the need for power plant removal cost data for various purposes.[1, 2] He then provides a data base of removal cost estimates from various utilities. These estimates are all escalated to represent final costs as estimated in 1997. The figures he provides are net of any salvage. The data is presented sorted by the type of power plant. This type of data base is very valuable and Ferguson is congratulated for making it public and available to all.

However, Ferguson's use of the data is over simplified. He simply calculates the average cost per kw for the various types of plants and for all plants combined. He has not provided any justification for using the kw size of the plant as the sole determinant of removal cost. Indeed, in his verbal explanations he provides explanations of various other factors that can influence costs.

If we examine Ferguson's data with statistical analysis, we see several problems. [I review here only the data for coal and lignite plants, but similar problems can be expected in the other categories.] Figure 1 is Ferguson's data for coal-fired power plants, with removal cost plotted as a function of plant size in KW. The first problem that we observe is the broad scattering of data points. While there is some indication of a pattern, many data points do not fall within the pattern.

The second problem shows up when we try to regress removal cost as a function of kw size. The best fitting simple line is not simply $43/kw. The relationship isn't even linear. The relationship is that removal cost [y] is equal to -9.55 + 1.64 times the square root of size [x].

The third problem is that the r^2 of this best fitting simple line is only about 0.34. This tells us that only about 34% of the variation in cost is related to a variation in size. In fact even the best fitting curve of the 3000 or so analyzed has an r^2 of 37% and that was a very complex type of curve. This tells us that most of the variation in removal cost is related to something other than the size of the plant.

Figure 1 also shows us the 99% confidence interval [plus or minus three standard deviations] around the regression line. Several points lie outside this interval. These can simply be called outliers, or they can be recognized as cases where even less of the cost is proportional to size than those cases within the confidence interval. Since costs in those cases are not related to plant size, they should not be included in our study of the relationship of removal costs to plant size. If we delete those points from the data, we can get a new regression.

The data and regression line are shown in Figure

2. Our new equation is y = -7.21+ 1.39 times the square root of plant size. In this case our r^2 has improved to 53%. This indicates that even with dropping the bad points, we still have only about half of our variation in removal cost explained by variation in plant size. Once again we have several points that lie outside the confidence interval. Assuming once again that these points have a less than usual relationship to cost, I deleted them and ran the regression again. That resulted in Figure 3.

Our new equation from Figure 3 is y = -12.07 + 1.55 times the square root of plant size. Our r^2 has now improved to about 70%. This still leaves about 1/3 of our variation in removal cost related to something other than plant size. To this point we have eliminated just 7 points out of more than 100, but further removal of outliers is not justified. For that matter, our removal of these seven points may not be justified either, if they are powerful indicators of a relationship where removal cost is significantly related to other variables than the size of the plant..

Now suppose that we insist that the removal cost relationship has to be linear. That is, removal cost is equal to a fixed cost and a variable cost. Figure 4 shows the resulting regression. The equation is y = 10.89 [fixed cost] + 0.0273 times plant size [variable cost]. The 0.0273 is per MW, so that corresponds to about $27/kw in comparison to the $43 used by Ferguson, a reduction of 37%. Note, however, that we have the same outliers we had in the non-linear case.

If we remove those outliers, we get Figure 5. Our regression improves to an r^2 of 52%, nearly as good as the non-linear case. Our equation becomes y = 9.85 + 0.0236 times plant size. Now our $/kw has dropped to $23/kw after a fixed cost of about $10 million. Once again we have significant outliers, which we can delete.

Deleting these outliers, we get Figure 6. Our r^2 has improved to about 66%, not as good as the non-linear case. Once again, a third of our variation is not explained by plant size. The equation is now y = 6.61 + 0.0269 times plant size. We are back to about $27/kw.

Ferguson himself notes that there is some non-linearity in the relationship. He breaks his data down into various size groups and notes the difference: [3]

- plants under 100 MW, $64/kw
- plants between 100-250 MW, $57/kw
- plants between 251-500 MW, $43/kw
- plants between 501-750 MW, $41/kw
- plants between 751-1000 MW, $26/kw
- plants over 1000 MW, $18/kw

Note that these are **plant sizes** not generating **unit sizes.** Ferguson states that this data "may be of value for evaluating the reasonableness of the terminal net salvage factors utilized for regulatory accounting." He then notes, "The summaries herein do not provide a basis for judging the validity of individual site-specific studies."[4] Also, in one case that I know of, a colleage of Mr. Ferguson uses the $43/kw for the determination of net removal cost, regardless of the size of the plant.

I agree that Ferguson's data base can be useful as proxies for non-existent removal costs and as a check on other's calculated removal costs, but only with two caveats. First, recognition of the impact of different size ranges must be taken, either through regression, or looking at a smaller block of data. Second, the impact of other factors than plant size must be considered.

What are some of these other factors that may impact removal cost? Ferguson himself suggests that economies of scale and plant age must be taken into account. He also suggests 1) the presence of asbestos, 2) the boiler design, 3) the presence of ash ponds and scrubbers, and 4) the need for site restoration as having an impact on plant removal cost. I certainly agree that these and other factors could outweigh the importance of plant size in determining removal cost. However, Ferguson has not provided that data for any of his data base, so we can't check these factors in a regression.

What is the impact of these different regression equations on estimated removal cost? Table 1 shows a summary for various sized plants. Many modern plants were built with 3 or 4 units of 500 MW each for a total of 1500-2000 MW. Table 1 shows that in this size range, use of Ferguson's $43/kw overstates removal cost by about $20-30 million for the better regressions.

I have some further concerns with using these, or any, removal costs as a part of the depreciation of the plant. My concern is twofold: first, regulatory accounting, as contrasted with financial accounting, has traditionally required that expenses be "known or knowable" before they can be booked and charged as expenses. I suggest that these removal costs that are expected to occur many, many years in the future are neither known or knowable with sufficient accuracy to book them as a part of depreciation expense. In fact, many recent sales of power plants have been at values well above net book value. This would argue for positive net salvage or negative net removal costs.

Ferguson argues that since land is not depreciated, and since an increase in plant value at sale is related to site value, then no recognition needs to be taken of this increase in plant value. I believe Mr. Ferguson is confusing **site value** with **land value**. Any increase in site value may have nothing to do with an increase in land value, but be related to **improvements** in the site, many of which are depreciable, and if of value can become, in effect, items with a large positive salvage. Moreover, there is really no data available that indicates that the increase in sale value is only related to site value. A purchaser may well have decided that the equipment in a plant can be efficiently used for longer than the present owner's depreciation life. We just don't know what the purchasers are valuing. However, continuing to collect a positive net removal cost while ignoring the increase in plant value shown in recent sales, is foolish.

Even if the removal costs were known and knowable, there is another problem. That is, we are collecting the money for an expense **before** we need to spend the money, without crediting the account for the interest earned on the early deposits. Some have suggested that including removal cost in depreciation makes for a larger depreciation than otherwise, reducing net book value, and thus reducing utility earnings and revenue requirement. They suggest that this offsets the missing interest on the pre-collected removal cost.

I agree, **if** the utility earnings rate exactly matches the discount rate used to calculate the future value of the pre-collections, and **if** the plant lasts exactly as long as the depreciation life. If these conditions are not met, then significant over-collection or under-collection of removal cost can result. I think, on the whole, it is far wiser to look at removal costs when they occur. At that point in time, they are certainly known and knowable. I recognize that if positive removal costs do result at that time, then current ratepayers have not paid the full cost of the power that they have been receiving. However, based on recent sales, I suggest that positive removal costs are unlikely.

As an alternative, I suggest that if removal costs are collected as a part of depreciation expense, then they ought to be collected at an extremely conservative rate. That would make the "truing up" at the time of actual removal much less financially painful.

CONCLUSION

If these studies are used to validate power plant removal costs or as substitute plant removal costs, a statistical relationship between plant size and removal cost should be used rather than the simple average calculated by Ferguson. Also, the impact of other factors than plant size should be considered, as well as some recognition of the interest earned on pre-collections

However, the question still remains whether net removal costs should be charged to depreciation at all before the plant is removed from service and the plant specific removal costs are known. If so, recent sales indicate that a positive net salvage is more appropriate than the negative salvage [positive removal cost] shown by Ferguson.

REFERENCES

1. Ferguson, John, "Power Plant Removal Costs," Journal of the Society of Depreciation Professionals, Vol. 5, No. 1, 1993, pg 39-42.

2. Ferguson, John, "Power Plant Removal Costs Revisited," Journal of the Society of Depreciation Professionals, Vol. 7, No. 1, 1996-97, pg 31-47.

3. Ibid, Figure 2, page 3 of 3.

4. Ibid, page 36.

Price Caps and Depreciation

Don Bjerke

Abstract

It is recommended that Total Factor Productivity (TFP) indices be developed in establishing price caps for specific segments of a company. The implications of developing segmented TFP indices on depreciation are discussed in this paper.

The opinions expressed in this paper are those of the author and do not reflect those of SaskTel or any other company.

Introduction

Most Canadian telecommunication companies have come under price cap regulation as of January 1, 1998. Within the price cap formula a Total Factor Productivity (TFP) index is used in setting prices. At the end of a review period, companies are expected to provide the Commission with annual total company TFP results for the period 1995 to 2000[1]. This author[2] suggests that segmented TFP indices in addition to a total company TFP index be calculated. Segmented TFP indices would reflect the different efficiencies within segments of the company and be used to set price caps for different baskets and sub-baskets of service offerings (e.g. various local service offerings)[3].

Segmented Total Factor Productivity (TFP) Indices

The price cap formula is composed of three basic components which, in total, reflect changes in the industry's long-run unit costs and determine the maximum allowable change in prices, on an annual basis, for a basket of capped services. These are inflation index, productivity offset and exogenous factors[4].

This author suggests that there is an increasing requirement to calculate TFP indices for separate segments of the company for the determination of these price caps. The present procedure calculates only one TFP index for the total company which is to represent all segments of the company. As increasing requirements are being placed on companies to segment their company, greater pressure will come to bear to develop separate TFP indices for each of these segments. The first of these requirements has come from Telecom Decision CRTC 95-21. This decision splits a company's rate base in order to comply with the new regulatory framework. This new framework will apply price cap regulation to the utility segment whereas forbearance will apply to the competitive segment. It is suggested that a utility type TFP index and not a corporate index would be more appropriate for use in determining price caps for the utility segment. A further requirement, which is more important to companies having sparsely populated areas, for a segmented TFP index is in regards to Telecom Public Notice CRTC 97-42 Service to High-Cost Serving Areas. This segmentation identifies subsidy requirements for high cost areas existing in the switching & aggregation and access & basic local segments within the utility segment in providing basic service to rural areas. For example, it is evident that the efficiencies in providing basic telephone service to rural areas verses urban areas are significantly different. The efficiencies that contribute to greater productivity in the urban network are obtained by large economies of scale on high density intracity routes and associated switching. These economies of scale are not present in sparsely populated rural areas where distribution networks are sized to the geographic area and the advantages of the economies of scale of technologies used can not be realized. Hence separate TFP indices for rural high cost areas and urban low cost areas should be determined in the establishing of price caps.

Calculating Segmented TFP Indices

Total Factor Productivity inputs of labour, material and capital presently expressed on a corporate basis should be expressed on a segmented basis[5]. Cost separation studies would be used to convert corporate records into segmented accounting statements. These systems would be used in providing the segmented labour, material and capital inputs. The labour input refers to the number of hours worked by employees in each segment and excludes time (not worked) such as statutory holidays, vacation leave and sick leave. Capitalized hours are also not included. The material input refers to such items as insurance costs, operating rents, advertizing expenses, automobile and travel expenses for each segment. The capital input refers to the stock of physical assets used in providing telephone service on a segmented basis. To develop the capital input, investment ratios would be used to assign plant additions on a vintage basis within outside and inside plant categories to segments (i.e. rural high cost and urban low cost access & basic local segments). Once the plant additions are assigned, their booked dollars would be restated to constant dollars using Telephone Plant Indices. These restated additions, the estimated service life, the survivor curve, and the net salvage value would be used to calculate the gross and net plant values for each segment. The above inputs along with their associated outputs (stated in constant revenue dollars) are then used to produce the TFP index which measures the relative increase in output to the relative increase in input between designated years.

Conducting Depreciation Studies

Mortality data maintained on a vintage basis forms the foundation for both TFP and mass property depreciation studies. This author suggests that the new network technologies such as digital switching and fibre demonstrate mass property characteristics. Retirements for these technologies are more dependant upon the duration the plant is in service rather than on the subsitutional effects of replacement technologies. Mass property studies are also much easier to conduct than integrated or product life studies. The average service life, the survivor curve and the net salvage characteristics are common elements for both a TFP and a depreciation study. These characteristics used in a depreciation study will meet the first objective of the depreciation process of determining the expenses attributable to each year's operation. An additional step in order to complete the depreciation study is required, however, to meet the second depreciation objective which is to recover the capital invested in depreciable plant over its useful life[6]. This is where remaining life adjustment procedures come into play in determining the final depreciation rate since TFP studies are not concerned with reserve deficiencies or surpluses.

NX Survivor Curves

The process of converting plant additions and their associated parameters from plant categories to segments such as rural high cost and urban low cost access & basic local segments requires combining parameters such as survivor curves for a number of plant categories. These survivor curves would be directly weighted by their investment to develop a composite survivor curve relating to each segment. The ability to combine survivor curves of various shapes for a number of various sized categories is not inherent within the capabilities of existing common survivor curves. This unique characteristic, however, is inherent within the NX survivor curves[7]. The NX survivor curves were developed to merge the time dependent characteristics of the normal density function with the time independent characteristics of the negative exponential density function to produce survivor curves that compares favourably to the Iowa State, the Kimball and the Gompertz-Makeham. The advantage of the NX survivor curves is that the curves may be described by a relatively simple formula that represents an infinite family of curves whose only controlling parameters are the average service life and the unitized variance. For developing composite values of other parameters, it should be noted that reciprocal weighting should be used when developing a composite average service life for a segment. Direct weighting can be used in developing a composite net salvage value for a segment.

Source Data

Methods used in determining the depreciation expense in the telecommunication industry are being significantly modified due to the introduction of new systems such as System Applications and Products (SAP) and the allowance of less rigid depreciation procedures permitted under GAAP. Traditionally, group accounting methods have been used to depreciate homogeneous groupings of plant items using survivor curves that represent the group's dispersed retirement patterns. These new systems are built to depreciate plant investment on an individual items basis over a designated amortization period. Traditional methods assume plant items are fully depreciated upon retirement whereas these systems realize a gain or a loss upon retirement. Since depreciation will play a lesser role under price cap regulation, there is more emphases being placed on simplifying and streamlining the process. This author feels, however, that this streamlining process is being conducted with total disregard to the mortality characteristics required in calculating the capital input to TFP studies. Determining plant mortality characteristics will not only serve the requirements for determining TFP indices but provide the requirements in conducting proper depreciation studies. Hence, the depreciation studies that once provided plant mortality characteristics to a TFP calculation should now become an integral part of the TFP calculation process.

Conclusion

In addition to a corporate TFP index, segmented TFP indices should be calculated to reflect efficiencies due to economies of scale within the company. This would be particularly useful in setting price caps for basic telephone service to high cost rural and remote regions of Canada. The development of segmented TFP indices require the use of a unique type of survivor curves called the NX survivor curves. Mortality data forms the basis of conducting both TFP studies and proper depreciation mass property studies. The source of this information must continue to be maintained within the company. Mortality characteristics such as service life, survivor curve and net salvage are common to both the TFP study and the depreciation study but remaining life adjustment procedures will be needed to complete the depreciation study.

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1. CRTC replaced Rate of Return regulation with Price Cap Regulation for most Canadian telecommunication companies as of January 1 1998 as per Telecom Decision CRTC 97-9 Price Cap Regulation and Related Issues.. In this decision the Commission states that it is of the view that all of the telephone companies, including NBTel and NewTel, should be prepared to provide the Commission, at the end of the review period, annual total company TFP results for the period 1995 to 2000 (paragraph 243).

SaskTel will fall under CRTC regulation as of June 30, 2000.

[2] Don Bjerke P.Eng. is a Management Consultant who was employed by SaskTel from 1965 to 1997. Most of his work experience while with SaskTel related to costing, economics, and depreciation. He may be reached at bjerke@sk.sympatico.ca

[3] Segments reflect the extent in which services are supplied on a monopoly or on a non-monopoly type basis. The monopoly type segments fall within the utility segment whereas the non-monopoly type segments fall within the competitive segment (Telecom Decision CRTC 94-19 Review of Regulatory Framework pages 15 & 16). Baskets on the other hand are service groupings based on criteria such as homogeneity and/or similarity in demand price elasticities (Telecom Decision CRTC 97-9 Price Cap Regulation and related Issues paragraph 118).

[4] Telecom Decision CRTC 97-9 Price Cap Regulation and Related Issues paragraph 29.

[5] Although Saskatchewan did conduct a Total Factor Productivity study in response to Interrogatory Saskatchewan (CRTC) 25 March 91-5201 with regards to it's (IX2) submission to the CRTC Telecom Public Notice 1990-73 Unitel Communications Inc. and B.C. Rail Telecommunication / Lightel Inc. -applications to Provide Long Distance Voice Telephone Services and Related Resale and Sharing Issues, all TFP indices were expressed on a corporate basis.

[6] These are the traditional objectives of depreciation accounting as stated in Telecom Decision CRTC 78-1 Inquiry into Telecommunications Carriers' Costing and Accounting Procedures Phase I: Accounting and Financial Matters page 4.

[7] The NX survivor curves were developed by Ralph Bjerke P.Eng. B.Comm. while employed at Edmonton Telephones.
An article on NX survivor curves is discussed in Volume 6, Number 1, 1994/1995 issue of the Journal of the Society of Depreciation Professionals entitled Relationship Between The Fisher-Pry and NX Distribution by Ronald J. Willis of Willis Manufacturing Ltd. While the article refers to the use of NX survivor curves for both mass and integrated properties, this paper refers to the use of NX survivor curves to only mass properties. This paper assumes that all properties are treated as mass for both TFP and depreciation studies.
An earlier article on NX survivor curves is discussed in Volume 5, Number 1, 1993 issue of the Journal of the Society of Depreciation Professionals entitled AProduct Life Cycles: A New Approach@ by R.Bjerke, pp 29-35.
NX curves were used to conduct Saskatchewan's TFP study mentioned in footnote number 5.

Comments of John Ferguson on 1998 Journal Articles
John Ferguson

I believe that several of the issues addressed by articles in the 1998 Journal of the Society of Depreciation Professionals deserve additional discussion. Some of these comments on the issues relate to the sensitivity of salvage and cost of removal ratios to the age of the retired property. Recognizing this sensitivity should be an important consideration when determining depreciation rates. Recognition is also an important consideration when discussing salvage, cost of removal and net salvage.

Age sensitivity leads to four net salvage classifications, Average, Current, Future and Past, only two of which are suitable for calculating depreciation rates. Future net salvage is used for remaining life rates. Past net salvage is combined with Future to calculate Average, which is used for whole life rates. While it is possible for Past net salvage to be the same as Average or Future, the age of past retirements is typically too young for this to occur. Current net salvage is not suitable for calculating depreciation rates, but can be useful as an interim step in the process of estimating Average or Future net salvage.

My article in the 1998 Journal expressed disappointment in the salvage and cost of removal discussion in the 1996 version of the NARUC publication, <u>Public Utility Depreciation Practices</u>. Therefore, readers may be interested in the discussions of age sensitivity in <u>Accounting for Public Utilities</u> by Hahne and Aliff and in the A.G.A. and EEI publication, <u>An Introduction to Net Salvage of Public Utility Plant</u>.

<u>Capital Recovery Policy: The Decision Makers</u>, by Ronald Kalich

Mr. Kalich's article presents a view of the decision makers that shows the Accounting, Engineering, Forecasting and Budgeting viewpoints converging upon the policy from the four points of the compass, and suggests that other convergences are possible. These four viewpoints apply to non-regulated entities. Regulated entities have a fifth viewpoint – that of the regulator –that is likely to have more influence on depreciation rates than the other four.

Depreciation is an accounting concept, so the Accounting viewpoint should be controlling in both regulated or non-regulated environments. However, accounting tends to not be the controlling consideration under regulation, because regulatory decisions tend to emphasize the short-term effect of depreciation changes. Short-term emphasis leads to low depreciation rates that are detrimental to customers in the long-term, because rate base regulation causes the initial impact of depreciation changes to reverse within a few years.

The determination of depreciation rates is a technical process that essentially is an effort to predict the future. Therefore, the Engineering and Technical viewpoints converge upon (feed) the Accounting viewpoint, and the Budgeting viewpoint (for non-regulated entities) results from the Accounting viewpoint. These relationships lead these viewpoints to take the form of a Y. For regulated entities, the Regulatory viewpoint would sit between the Accounting and Budgeting viewpoints, as under Statement of Financial Accounting Standards No. 71 (SFAS 71) the regulator specifies the depreciation to be recorded. Those dealing with regulated entities recognize that regulation typically causes the recording of depreciation to be deferred. This situation is evident from the large asset impairment write-offs of the telecommunications industry in recent years and the current concern of the electric industry for stranded costs.

Mr. Kalich does not discuss the elements of capital recovery policy, which are stated for regulated entities on page 44 of my 1998 Journal article.

Reuse Salvage Adjustments in Life and Salvage Analysis, by Charles P. Neff

Mr. Neff addresses an issue that is important and deserves expansion, because several factors can combine to cause the salvage from reused materials to exert an unwarranted influence on depreciation rates. These factors include how retirement amounts are determined, the age of retired items, and how the salvage value of reused materials is determined. However, this issue is likely to be of more significance to electric utilities than to gas utilities, because components of aboveground facilities are more likely to be reused than are components of underground facilities.

The significance of salvage and cost of removal as ratios of retirement amounts is influenced by the relationship between the actual age of retired items and the age utilized to determine amounts to record as retirements. For example, first-in-first-out (FIFO) aging is a legitimate retirement pricing procedure that will produce aged data suitable for life analysis, but is likely to cause the past salvage ratio to significantly overstate the average or future salvage needed to calculate depreciation rates. Only cost escalation affects the cost of removal ratio. Therefore, FIFO pricing may produce an average dollar age of retirements that is close enough to the expected age of the average or current survivors upon retirement for past cost of removal to be a reasonable indicator of the average or future cost of removal.

If the age of retired property is about the same as the expected age of the average or current survivors upon retirement, past salvage is likely to be a reasonable indicator of the average or future salvage. However, growth and cost escalation typically cause the age of retired property to be much younger than the expected age of the investment upon retirement. Young items are more likely to be reused, so the past salvage ratio will reflect a larger portion of reuse than can be expected in the future, thereby overstating the ratio appropriate for depreciation rate calculation.

Generally accepted accounting principles (GAAP) specify that salvage be recorded at the lower of cost or market value, but regulated entities can depart from this requirement. When materials and supplies inventories were maintained manually, the practical choice for treating a reused item was to adopt the current average inventory cost (market value) as the salvage value. This treatment can be used by entities that qualify for the special accounting allowed by SFAS 71, but it inflates salvage value. Some utilities have recognized that record mechanization allows different treatment, and have changed to adopting estimated original material cost or some fraction thereof. Entities that have not yet made such a change should consider doing so, as the write-up inherent in the current average inventory cost compounds the problem Mr. Neff addresses.

Mr. Neff's example is based on direct weighted life and on past net salvage. Adopting reciprocal weighted life (equal life group) would help by increasing the Year 1 depreciation amount from \$720 to \$810. Recognizing the future net salvage that should be utilized to calculate remaining life depreciation rates would also help.

Reciprocal weighting and future net salvage do not address the fact that reused items have already lived a portion of their lives. Adopting some fraction of the estimated original material cost (perhaps even zero) would address this problem.

Technological Obsolescence: Assessing the Loss in Value on Utility Property, by Stephen L. Barreca

Mr. Barreca addresses what I consider to be the most important aspect of determining depreciation rates – developing the understanding needed to judge whether the past can be relied upon as a predictor of the future. Developing this understanding is also the most interesting aspect of depreciation. Depreciation literature typically discusses the need for this understanding, but provides little guidance on how to accomplish it.

Mr. Barreca's discussion is of more value to non-regulated entities, because the regulatory viewpoint makes it difficult to successfully introduce anything that increases depreciation rates. He discusses influence on life. Salvage and cost of removal also deserve consideration, because past experience may not be representative of the average net salvage required for whole life rates or the future net salvage required for remaining life rates. An advantage of addressing salvage and cost of removal is that the past can be viewed in a manner that estimates how much different the future will be, so is easily dealt with when determining depreciation rates. However, no matter how soundly based, average and future net salvage lead to increased depreciation rates, so usually prove impossible for regulated entities to incorporate.

<u>Unit Cost Methods for Determining Net Salvage for Mass Accounts</u>, by Dave Berquist

Mr. Berquist addresses how to react to situations when past net salvage is not available or provides a misleading indication of the average or future net salvage needed to calculate depreciation rates. This is an important subject, as past net salvage is rarely the same as the average or future net salvage. It should be recognized that the approaches Mr. Berquist discusses should be implemented using the expected price level at the time of doing the work. This would be the year well plugging would occur for his Example 1 and the expected average removal year for the towers for his Example 2.

Example 2 distinguishes between interim retirements and terminal retirements. It is important that the interim/terminal retirement assumption reflected in the net salvage estimate be consistent with the assumption reflected in the life estimate, as inconsistency can lead to absurd conclusions. For example, I was recently involved in a proceeding in which a party asserted that past retirements were piecemeal (interim) and that more extensive (terminal) retirements in the future would produce economies of scale that would decrease removal costs. One of the property groups for which this assertion was made was currently experiencing retirements of an average age that the dispersion pattern indicated the annual retirements would be 0.94% of the original placements. This pattern indicates the maximum annual retirements will be 1.39% of the original placements, so there is little room for the claimed economies of scale to occur. Example 2 requires a quite narrow dispersion pattern to produce a meaningful distinction between interim and terminal retirements.

Example 3 for gas services illustrates the value of material type segregation when dealing with salvage and cost of removal. Mr. Berquist suggests that an old material type producing highly negative net salvage ratios may not be a reasonable indicator of what can be expected for newer material types. My experience with material type segregation has been much different. I have found the age of old material type retirements, such as wrought and cast iron, to often be close enough to the expected age upon retirement of the newer types, such as steel and plastic, for this experience to be a reasonable indication of the average or future net salvage applicable to the surviving property. The sensitivity of salvage and cost of removal ratios to age becomes clear when distribution mains and services are segregated by material type, which leads me to utilize this segregation whenever possible. However, when material segregation is not possible, other methods are available for demonstrating age sensitivity.

When considering material type differences, it is important to recognize the influence, if any, of installation cost differences. The retirement processes for mains and services do not vary much by material type, so it is not the numerator of the cost of removal ratio that deserves consideration. Plastic pipe exists because its installed cost is less than steel, so, given the same age upon retirement, plastic pipe may warrant a higher cost of removal ratio than steel pipe.

Mr. Berquist's use of unit removal costs for Example 3 demonstrates an approach to estimating average or future net salvage that is available to entities that utilize standard costing to determine recorded cost of removal. It becomes a simple matter to apply the standard cost process to the inventory of surviving property, thereby calculating the cost of removal amount that would be incurred if all the property is removed or abandoned now. It is also a simple matter to adjust this current amount to the expected price level at the time the average service life and dispersion pattern indicate the average or current survivors would be retired.

The -20% net salvage Mr. Berquist determines for Example 3 is not suitable for calculating a depreciation rate, because it does not represent the expected net salvage amount at the time the 100,000 services would be retired. Example 4 is also not suitable, because Mr. Berquist relates the average age of retirements to the current age of the survivors. The appropriate relationship is to the expected age of the average or current survivors at the time of their eventual retirement. Example 4 does not disclose the type of property, but does disclose the age of past retirements (30 years) and the current age of survivors (22 years). It would not be unusual for the average service life to be at least double the age of retirements and at least triple the age of survivors. Therefore, instead of decreasing the past net salvage ratio of -90% to a current ratio of -45% by removing eight years of inflation, Mr. Berquist should have increased the -90% by adding at least 30 years of inflation.

<u>A Combined Index in Simulated Plant Record Analysis</u>, by Kimbugwe A. Kateregga

Mr. Kateregga addresses a situation that has vexed depreciation analysts ever since Mr. Bauhan developed the SPR approach. The difficulty arises, because data often do not meet the conditions Mr. Bauhan indicated are needed for SPR to provide reliable results. For example, the attached chart is a graphical representation of Mr. Kateregga's addition and retirement data expressed in relation to his beginning plant balances. As is evident, they are a bit lumpy and I left out the first ten years when the account was in its infancy. The retirement ratios are multiplied by ten to make them more visible.

Lumpiness causes SPR analyses to think change is occurring, which leads the computer to land on the widest or the narrowest dispersion patterns. This situation causes some analysts to exclude the Iowa O curves from SPR analysis. I view this situation as a message to get behind the numbers, and about 30 years ago Bill Caunt, a contemporary of Mr. Bauhan who helped Mr. Kateregga with his article, developed an SPR output report format that I have found helpful. Mr. Caunt's approach was to create matrixes of the best fit average service life and respective index of variation for each of 27 Iowa L, S and R curves (the square curve is excluded) as if the analysis was done at the end of each of the last ten years, and to indicate if each listed life is the only one that produces a zero difference between the calculated and actual retirements or balances. This output aids the analyst in sorting out the influence of data lumpiness, which is a good first step toward getting behind the numbers to develop an understanding of the past.

An SPR analysis that simulates retirements is more sensitive to data lumpiness than is an analysis that simulates plant balances. This leads those conducting studies that emphasize the measurement of history to favor the SPR balances procedure, and those conducting studies that emphasize the understanding of history to favor the SPR retirements procedure.

<u>Economic Depreciation?</u>, by the NARUC Staff Subcommittee on Depreciation

What I consider to be the most significant reason for not using economic depreciation for regulatory purposes is not mentioned. The GAAP definition of depreciation accounting states "it is a process of allocation, not of valuation." Therefore, economic (value) depreciation conflicts with accounting principles.

However, there is an aspect to this discussion that is missing from the article. On page 46 of my article in the 1998 Journal, I fault the authors of the 1996 NARUC publication for the assumption that life is measurable only by time. The authors repeat this assumption in their discussion of economic depreciation. If measurement of life is not limited to time and the depreciation accrual patterns depicted on Figure 1 of the article are generated by identical patterns of production, the increasing and decreasing accruals would match to asset usage, so could be adopted for accounting purposes. However, most utility property exhibits constant usage, so the straight-line approach is appropriate. There are some types of property that exhibit a decreasing usage pattern over their lifetimes, so would justify a decreasing pattern of depreciation. There are also some types of property that exhibit an increasing usage pattern in their early years of life, so would justify an increasing pattern of depreciation that would change to straight-line