STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY ("IPL") FOR AUTHORITY TO INCREASE RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE AND FOR APPROVAL OF: (1) ACCOUNTING RELIEF, INCLUDING IMPLEMENTATION OF MAJOR STORM DAMAGE RESTORATION RESERVE ACCOUNT; (2) REVISED DEPRECIATION RATES; (3) THE INCLUSION IN BASIC RATES AND CHARGES OF THE COSTS OF CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY; (4) IMPLEMENTATION OF NEW OR MODIFIED RATE ADJUSTMENT MECHANISMS TO TIMELY RECOGNIZE FOR RATEMAKING PURPOSES LOST REVENUES FROM DEMAND-SIDE MANAGEMENT PROGRAMS AND CHANGES IN (A) CAPACITY PURCHASE COSTS; (B) REGIONAL TRANSMISSION ORGANIZATION COSTS; AND (C) OFF SYSTEM SALES MARGINS; AND (5) NEW SCHEDULES OF RATES, RULES ANDREGULATIONS FOR SERVICE.	)	**CAUSE NO. 44576**
IN THE MATTER OF THE INDIANA UTILITY REGULATORY COMMISSION'S INVESTIGATION INTO INDIANAPOLIS POWER & LIGHT COMPANY'S ONGOING INVESTMENT IN, AND OPERATION AND MAINTENANCE OF, ITS NETWORK FACILITIES	)	**CAUSE NO. 44602**

TESTIMONY OF

EDWARD T. RUTTER – PUBLIC'S EXHIBIT NO. 10

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

JULY 27, 2015

TESTIMONY OF OUCC WITNESS EDWARD T. RUTTER
CAUSE NOS. 44576/44602
INDIANAPOLIS POWER & LIGHT COMPANY

I. INTRODUCTION

Q: Please state your name, employer, current position and business address.

A: My name is Edward T. Rutter. I am employed by the Indiana Office of Utility Consumer Counselor ("OUCC") as a Utility Analyst in the Resource Planning and Communications Division. My business address is 115 West Washington St., Suite 1500 South Tower, Indianapolis, Indiana 46204. My educational background, professional experience and preparations for this case are detailed in Appendix A attached to this testimony.

Q: What is the purpose of your direct testimony?

A: I will address the following issues:

(1) The original cost and accumulated depreciation for certain accounts, sub-accounts and assets of the Indianapolis Power & Light Company ("IPL") that reflect a net negative utility plant in service balance at December 31, 2013. These accounts, sub-accounts and individual assets are detailed in IPL witness Mr. John Spanos' JJS Attachment 1 (Part 1), pages 56 – 59 of 169, which is the 2013 Depreciation Study prepared by Gannett Fleming Valuation and Rate Consultants, LLC ("2013 Depreciation Study").

(2) The discount rate utilized by IPL Witness Mr. John J. Reed in determining the "fair value" of the Steam Production Plant.

(3) IPL's request for the implementation of new or revised rate adjustment mechanisms to recover lost revenue from Commission-approved Demand-Side Management ("DSM") programs.

(4) The level of operation and maintenance expenses incurred by IPL from 1994 through 2014 recorded in FERC account 584 Underground Line Expenses and account 594 Maintenance of Underground lines.

II. IPL's NET ORIGINAL COST OF UTILITY PLANT IN SERVICE

Q: In establishing IPL's future base rates, should the Commission approve the depreciation rates recommended in Mr. Spanos's direct testimony and the 2013 Depreciation Study?

A: Yes. However, I have concerns relative to the accounts and sub-accounts that I have identified as having net negative utility plant balances (utility plant in service less accumulated depreciation resulting in a negative balance for a specific account or group of accounts) as of December 31, 2013, as detailed on ETR Attachment 1. The continued depreciation on those Accounts that had a negative utility plant in service balance at December 31, 2013 may not be in the public interest for the following reasons:

- The current depreciation rates have been in effect for almost thirty years.
- The 1993 Depreciation Study indicated that the depreciation rates for Electric Distribution Plant would reduce annual depreciation expense by $2,359,241. (See discussion at p. 5 below).
- The 2013 Depreciation Study states "[a]n assumption that accrual rates can remain unchanged over a long period of time implies a disregard

for the inherent variability in service lives and salvage and for the change of the composition of the property in service."[1]

- The 2013 Depreciation Study also states that "[f]or most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2013, is reasonable for a period of three to five years."[2]

Q: In reviewing the 2013 Depreciation Study, were you able to determine the net book value of the IPL utility plant in service by FERC account at December 31, 2013?

A: Yes. From Mr. Spanos' JJS Att. 1 (Part 1) pages 56 – 59, I was able to derive the net original cost in service by account, sub-account and for specific steam generating plant facilities and distribution plant as of December 31, 2013. The referenced data provided the original cost and book depreciation reserve. My computations based on that information show that there are several accounts, sub-accounts and specific steam production plant facilities that have a negative net utility plant in service balance as of December 31, 2013, and the cumulative negative net utility plant in service balances at December 31, 2013 total ($105,894,617).[3]

Q: Does a negative net utility plant in service balance impact the overall revenue requirement and rate calculation in this cause?

A: Yes. It is important to understand the difference between depreciation expense and accumulated depreciation. Depreciation expense is recovered through rates and represents a loss in service value not restored through current maintenance,

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[1] 2013 Depreciation Study, prepared by Gannett Fleming Valuation and rate Consultants, LLC, page VI-2.
[2] *Id.*
[3] See ETR Attachment 1.

while accumulated depreciation is a key element of the utility's rate base. The rate base represents a utility's investment in the facilities devoted to providing utility service, net of accumulated depreciation. The level of depreciation expense ultimately allowed to be included in rates by the Commission, and how the net negative utility plant in service balances are treated in the development of the rate base, impact the rates IPL's customers will pay.

Even though IPL's depreciation study shows net negative utility plant in service balances at December 31, 2013 for accounts 311, 312, 312.3, 312.3, 314, 316, 364, 365, 371 and 373, IPL is still proposing to collect \$20,039,710[4] annually *just for those accounts* through its rates. In other words, the \$20,039,710 represents depreciation expense on utility plant in service that was already fully depreciated as of December 31, 2013.

By including depreciation expense on fully depreciated assets in its revenue requirement, IPL is asking current ratepayers to keep paying for the value of assets IPL has already fully recovered.

Q: Is it problematic to rely on depreciation rates that remained unchanged since Cause No. 37837, decided on August 6, 1986, almost thirty years ago?

A: Yes. While the depreciation rates approved in Cause Nos. 37837 were appropriate as of June 30, 1985, over a period of almost thirty years those rates resulted in negative utility plant in service for certain steam production plant facilities and distribution plant accounts. Certain accounts have not only been fully depreciated, but have resulted in a negative net utility plant in service balance of

[4] See ETR Attachments 1 and 4.

$105,894,617. IPL's 2013 Depreciation Study depicts the continued depreciation of these Accounts as the recovery of the assets' original cost and the removal cost, net of any salvage value.[5] As explained by Mr. Spanos, "[n]et salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage."[6]

In my review of the "Book Depreciation Study of Electric Utility Property as of December 31, 1993"[7] ("1993 Depreciation Study"), the recommended composite rate, or effective depreciation rate for a group of accounts within a specific utility plant category, for Electric Distribution Plant was 4.68%, which was lower than the corresponding existing composite rate of 5.11%. Use of the lower composite rate would have resulted in an annual decrease in IPL's depreciation expense of $2,359,241. See Schedule 1, page 2 of 2, 1993 Depreciation Study.[8] For illustrative purposes, the cumulative impact of that decrease over the period of August 24, 1995 to June 30, 2014 is $44,825,579 ($2,359,241 * 19 years), which is approximately 52% of the net negative distribution plant in service balances at December 31, 2013 of $86,355,172. Mr. Spanos stated the following:[9]

> Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. *An assumption that accrual rates can remain unchanged over a long period of time implies a disregard*

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[5] IPL Witness JJS Attachment 1 (Part 1) pages 56 – 59 of 169.
[6] IPL witness Spanos direct testimony, page 11, line 6-9.
[7] ETR Attachment 5.
[8] *Id.*
[9] IPL Witness JJS Attachment 1, page 54.

> *for the inherent variability in service lives and salvage and for the change of the composition of the property in service....*
>
> The annual depreciation accrual rates are applicable specifically to the electric plant in service as of December 31, 2013. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2013, is reasonable for a period of three to five years. (Emphasis added.)

In light of the net negative utility plant in service balances at December 31, 2013, Mr. Spanos's statements underscore that it was unreasonable to apply the depreciation rates approved in Cause Nos. 37837 and 39938[10] for a period of almost thirty years. Not only has that policy resulted in IPL over-depreciating certain assets, it likely has resulted in ratepayers overpaying for electric service during the thirty years since the last depreciation study.

Q: What other factors besides the approved depreciation rates could have caused a negative net original cost of utility plant in service for certain assets at December 31, 2013?

A: In addition to the three new trackers IPL is seeking to establish in this Cause, IPL's ratepayers are currently subject to construction work in progress ("CWIP") trackers, which permit tracking of certain pollution control investments. In reviewing the Commission Orders in Cause Nos. 42170, 42700, 43403 and 44242, an estimated useful life of 18 years was adopted for purposes of computing depreciation expense associated with Qualified Pollution Control Property. While allowable and in line with Commission orders, the use of an 18-

[10] IPL filed a Book Depreciation Study as of December 31, 1993 in Cause No. 39938; however the parties in that Cause, including the OUCC, agreed to not change the depreciation rates that were then in effect, approved on August 6, 1986 in Cause No. 37837. The composite depreciation rate approved in Cause No. 37837 for Steam Production Plant was 2.87%, which equates to a composite remaining life of approximately 35 years.

year estimated useful life in those proceedings is inconsistent with the composite remaining useful life of 35 years implicit in IPL's approved depreciation rates.

Q: Do you believe that IPL may have over-collected from ratepayers during the last twenty years based on negative utility plant in service balances at December 31, 2015?

A: Yes, it is possible that IPL over-collected.[11] The current depreciation study shows that as of December 31, 2013, IPL has depreciated certain assets $105,894,617 more than the original cost of those assets.[12] While this amount was lawfully collected, due to the age of the current depreciation rates and the planned major changes to IPL's generating facilities[13] in the near term, I recommend that the future accruals for those accounts with a negative net plant in service balance at December 31, 2013 be monitored closely to determine if ratepayers are being overcharged.

Q: What does the OUCC recommend to address its concerns?

A: Even though the current depreciation rates have been in effect for almost thirty years and the magnitude of the negative net utility plant in service balances for certain Accounts is $105,894,617, the OUCC recommends in this proceeding that the Commission approve the future accruals for those Accounts that have a negative net utility plant in service balance at December 31, 2013. The rates established in this proceeding are expected to be in effect for a relatively short

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[11] Legally IPL did not over-collect since it collected for expenses approved by the Commission in a base rate proceeding. Only in assessing the current situation looking forward can it be said it has over-collected.

[12] The change in the number of customers and in their usage since the current rates were implemented impact what amount actually was recovered from customers, and may be higher or lower than what was expected originally.

[13] Those contemplated major changes are: the construction of the Eagle Valley Combine Cycle Gas Turbine ("CCGT"), the retirement and removal from service of the existing Eagle Valley coal generating facility, the conversion to natural gas of Harding Street Units 5 and 6, and the proposal to convert Harding Street Unit 7 to natural gas.

period of time. IPL states it will be filing a second rate case to reflect revenue requirements of the new Eagle Valley CCGT. The OUCC recommends a new depreciation study be provided at the time of the next rate case. The OUCC also recommends that the impact of the future depreciation expense accruals for those accounts that have a negative net utility plant in service at the end of the test year (June 30, 2014) be evaluated again in IPL's next rate case or no later than five years hence, whichever comes first.

Q: Do the negative plant in service balances at December 31, 2013 for the four Distribution Plant accounts 364, 365, 371 and 373 have any connection to the recent distribution plant explosions that have occurred in downtown Indianapolis?

A: No. The fact that there are negative plant balances in the four identified distribution plant accounts at December 31, 2013 would not impact or cause those occurrences. However, since the negative plant-in-service balances represent the accumulation of net negative salvage for those accounts, then those funds should be available to address issues related to the explosions. The aggregate negative plant balance for distribution plant accounts 364, 365, 371 and 373 is $86,355,172, derived from ETR Attachment 1.

III. FAIR VALUE OF ELECTRIC GENERATING FACILITIES

Q: Have you reviewed the direct testimony, supporting exhibits, workpapers and any responses to OUCC data requests relative to the fair value recommendation for the IPL electric generating facilities?

A: Yes. I have, including the direct testimony and supporting exhibits of IPL Witness John J. Reed. In addition, I have reviewed and analyzed his workpapers, participated in several conference calls regarding his direct testimony and have met with IPL representatives to review his computations regarding his conclusion on the fair value of the IPL electric generating facilities.

Q: Are you familiar with the methodology that Mr. Reed adopted in valuing the generation assets owned by IPL?

A: Yes, I am. In this proceeding, Mr. Reed chose to value the assets individually and utilized the income approach in arriving at a fair value recommendation for IPL's electric generating facilities.

Q: Are you comfortable with the exclusive use of an income approach in developing a fair value for the IPL electric generation facilities as adopted by Mr. Reed?

A: No. The use of the income approach in this Cause requires adopting hypothetical income, expense and capital additions in developing the fair value of IPL's electric generation facilities. This method is speculative and unrealistic based on the existing ownership and use of those assets. For example, in the income approach, Mr. Reed has assumed that the steam production plant facilities would be sold to a non-regulated merchant generator, who then would enter into Purchased Power Agreements with IPL to purchase the power then generated.

Q: What about other valuation methodologies?

A: Traditionally in valuing an asset, group of assets, or a going concern, there are three valuation approaches: 1) the value of the underlying assets; 2) the income approach; and 3) comparable sales. Normally each of these approaches is developed and the analyst will apply different weights to the values determined under each approach. That value represents what a willing buyer and a willing seller would agree to in an open market determination to pay for such assets.

Q: Please describe your efforts to develop a comparable sales valuation for IPL.

A: My ability to develop a comparable sales analysis was hindered by the difficulty in obtaining data regarding actual sales of electric generating facilities. My search for publicly available information relative to electric generating assets that have been reported as sold to a third party operator uncovered only press reports of the electric generating facilities' capacity and sales price. Without having access to the actual documents, it is impossible to develop a comparable sales value. In utilizing a comparable sales approach one typically develops some sales ratio (i.e. sales price per nameplate capacity, as an example). If the only publicly available information is press reports of the sale price and nameplate capacity, then any ratio based on that information is suspect and should not be used in developing fair value. Therefore, there is insufficient information available to apply a comparable sales approach.

Q: Do you therefore agree with the fair value of the IPL electric generating facilities estimated by Mr. Reed under the income approach?

A: No. The basic premise utilized by Mr. Reed in developing the income approach is to ascribe income to electric generating facilities that are part of a unique integrated system made up of more than the IPL electric generating facilities. The income approach is utilized more effectively in determining value where income is already present as opposed to imputing income to a group of assets that contribute to the generation of income but do not currently generate income on a stand-alone basis. While the electric generating facilities are an integral part of the delivery of safe, adequate and reliable electric service to customers, the facilities are not stand-alone revenue producers. A group of assets like the IPL electric generating facilities are part of a sophisticated and integrated electricity generating, transmission and distribution system. Developing a revenue stream, operating expense and needed capital additions over a long term period is highly speculative and inconsistent with how those assets are being utilized. To be acceptable, this approach requires incorporation of the historical actual revenue, operating expenses and capital expenditures, and reasonable estimates for the future based on the historical actual costs, along with the operating experience and plans for the ultimate purchaser.

Q: Do you recommend adoption of Mr. Reed's determination of fair value for the steam production plant facilities?

A: No. His study is hypothetical and purely speculative. The cash flows are based on a hypothetical sale of the steam production plant facilities to a non-regulated merchant generator. He then develops a revenue stream, operating expenses and capital additions for those facilities for a long term period and then discounts the cash flows back to present value.

Mr. Reed adopted a Capital Asset Pricing Model ("CAPM") to estimate the cost of common equity, a pre-tax cost of debt as of June 30, 2014, based on the 30-day average yield-to-maturity of utility bonds with maturities of at least 20 years, and reasonable credit ratings. Mr. Reed also developed a hypothetical capital structure of 52.78% debt and 47.22% equity. The resultant discount rates were then adjusted for pre-tax property taxes.

The end result was that he adopted the following discount rates;

- Eagle Valley – 9.73%
- Georgetown – 10.07%

- Harding Street - 10.28%
- Harding Street CT – 10.28%
- Petersburg – 10.28%.

The above developed discount rates purport to reflect what a hypothetical investor would demand from an investment in these merchant generator companies. The discount rates utilized by Mr. Reed do not necessarily represent the return that new management would expect to achieve in evaluating the purchase of an asset, be it electric generation facilities or some other asset. Those decisions are made based on management's risk assessment, knowing what the investment market requires, the return developed by Mr. Reed, and what the internal target is for asset acquisition.

The internal management decision on asset acquisition typically is made on a pre-tax return basis and in my experience, valuing both assets and going concerns would typically be discounted in the range of 15% to 18%. I searched publicly available information for the five (5) companies Mr. Reed utilized as a sample group for an actual target return percentage for each merchant generator. I could not find what I would consider a reliable source or the actual transaction documents to provide me with a more precise return target.

Q: If your discount rates were used, how would that affect Mr. Reed's estimated fair value of the IPL electric generating facilities?

A: Mr. Reed's estimated fair value would be significantly reduced. As shown in ETR Attachment 3, the estimated fair value of the IPL electric generation facilities developed ranges from $1,076,649,184[14] to $381,610,440, utilizing Mr. Reed's workpapers and my suggested discount rates ranging from 15% to 18%.

Based on a 16.0% discount rate, the estimated fair value of IPL's Steam Production Plant Facilities would be no more than $494,272,762 or $582,376,422 less than Mr. Reed's estimated fair value. Thus, even if we accept Mr. Reed's hypothetical inputs to his model (which I do not), his proposed fair value of IPL's electric generating facilities is overstated by at least $582 million. Please see the testimony of OUCC witness Kaufman for a detailed discussion of fair value and fair value ratemaking in this Cause.

Q: Based on the inability to develop a meaningful comparable sales approach and the highly speculative hypothetical approach utilized by Mr. Reed in developing the fair value for the IPL steam production plant facilities, what is your recommended valuation approach?

A: Given that both the comparable sales approach and the income approach as developed by Mr. Reed are not supportable in this cause, the only typical valuation approach remaining is the value of the underlying assets. This latter approach is fully verifiable, represents how the steam production plant assets are currently utilized and is represented by the net original cost of the steam production assets at test year end.

IV. LOST REVENUES

Q: IPL Witness Mr. Lester H. Allen describes "lost revenues" as "a real and calculable cost of implementing DSM [demand side management] programs [.]"[15] Do you agree with that statement?

[14] IPL Witness Mr. Kelly direct testimony, page 8, Table 1.
[15] Direct testimony of IPL Witness Mr. Allen, page 7, lines 12 – 13.

A: Yes, but one needs to make sure that the calculation of "lost revenues" does not result in customers being charged more than the actual "lost revenues." As Mr. Allen notes, "[l]ost revenues are the contribution to fixed costs that the utility does not receive when customers participate in a utility sponsored DSM Program."[16]

Q: Do you believe there is the possibility in implementing a rate adjustment mechanism to collect "lost revenues" that ratepayers could be charged more than the actual "lost revenues?"

A: Yes. If in developing test year revenues, adjustments are made to sales for known and measurable changes, such as a change in annual sales volume, the lower sales attributable to DSM programs could be included in those rate adjustments. Such an inclusion would result in newly approved base rates capturing the lost sales attributable to DSM programs and correspondingly the "lost revenues." It would be a mistake to charge ratepayers again for "lost revenue" captured in the process of establishing new base rates.

The testimony of IPL Witness J. Stephen Gaske, Senior Vice President of Concentric Energy Advisors, Inc., addresses the Allocated Cost of Service Study ("ACOSS") and tariff design:

> [T]he level of customer charges for the residential and small commercial rate class were not increased to a level that fully recovers fixed costs at this time, and the inclining block structure of their customer charges was retained, so as to mitigate the impacts on smaller customers in those rate classes.[17]

[16] Direct testimony of IPL Witness Mr. Allen, page 7, lines 4 – 5.

[17] IPL Witness J. Stephen Gaske, p. 5.

However, Mr. Gaske also stated that "[w]ith respect to the residential customers I attempted to design rates that recovered a higher percentage of fixed costs in the customer charge and also tried to meet several additional criteria." *Id.*, p. 10.

Mr. Gaske's testimony appears to mitigate the need for recovery of "lost revenues" from DSM programs, since he advocates that IPL recover a higher portion of fixed costs from residential customers through the customer charge. His testimony implies that if the decision to mitigate the impact of rate changes on any one rate schedule was not made, IPL would be seeking a customer charge that recovers 100% of fixed costs, thereby eliminating any need for recovery of "lost revenues" from implementation of the DSM programs.

Q: In reviewing Mr. Gaske's direct and revised testimony and attachments, were you able to estimate what fixed charges would be collected from residential customers through the Customer Charge and the first usage block under the proposed revenue and filed ACOSS?

A: Yes. I performed my analysis on Rate RS to develop a fixed charge estimate assumed to be collected through new customer charges and the first usage block. In reviewing and analyzing IPL's Confidential Workpaper 1.0, JSG Workpaper 2.0 and 3.0, I was able to estimate that 58.45% of IPL's fixed costs assigned to Rate RS would be recovered through the customer charge and the first usage block, 500 kWh per month of the RS customers' bills.[18] The approved IPL DSM program for 2015 and 2016 is designed to save a little over 1% of kWh sales. Since the average customer usage is considered to be 1,000 kWh a month, on average any DSM savings would not materially impact the first usage block. A

[18] ETR Attachment 2.

bill analysis would be required to determine if any customers had actually used less than 500 kWh per month.

Q: Based on your estimate of the fixed costs percentage IPL is proposing to recover in the proposed tariff RS, what is the OUCC's position relative to the recovery of "lost revenue" in future years?

A: The OUCC recommends that any recovery of lost revenues account for the fixed costs that are recovered through the customer charge and the first block usage charge. To do otherwise would have the Rate RS customers paying more than the unrecovered fixed costs associated with the DSM "lost revenues." I would point out that OUCC witness Mr. Glenn Watkins proposes a rate design that is less front-loaded with fixed costs.

My recommendation stated above holds true for whatever the Commission ultimately decides with regard to rate design. In other words, whatever rate design is chosen the calculation of lost revenue must account for the fixed costs collected in the customer charge and the first block rate.

Q: Is it the OUCC's recommendation that in computing "lost revenues" the result should recognize that some portion of fixed costs are already recovered through the customer charge and the first tariff block?

A: Yes, otherwise IPL could be recovering an amount for fixed costs through the proposed tracker that is greater than the unrecovered fixed costs experienced by IPL for that particular period.

V. UNDERGROUND PLANT INVESTIGATION

Q. Mr. Rutter, were you tasked with reviewing and analyzing the costs incurred over a period of time by IPL and recorded in FERC Account Nos. 584 Operation Underground Lines and 594 Maintenance Underground Lines?

A. Yes. I was assigned to review and analyze the amounts recorded in FERC Account No. 584 and Account No. 594 for the period from 1994 through and including 2014. My analysis developed an average cost per reported underground distribution mile for that extended period of time. I was unable to develop the number of underground distribution miles for the last test year, June 30, 1992, calendar year 1992 and calendar year 1993 from publicly available information. I chose 1994 as my starting point, since it was the year closest to the test year where both underground distribution miles and the operation and maintenance ("O&M") expense information was publicly available.

I also sought out other publicly available information such as reports, whitepapers or Commission orders that might have some bearing on the data I was developing for my IPL analysis. The purpose of my analysis was to determine if historical spending for FERC account Nos. 584 and 594 provided information to supplement the analyses and conclusions reached by other OUCC witnesses.

Q. Did your analysis reveal any concerns that you believe should be brought to the Commission's attention?

A: Yes. In reviewing the actual expenditures recorded in accounts 584 and 594, I noticed that there was very little difference in IPL's cost per mile of underground distribution between 1994 and 2014. ETR Attachment 6 shows that the maintenance cost per underground distribution mile in 1994 were $563 (FERC account no. 594), while the corresponding cost for 2014 was $572, a difference of only $9 per mile or 1.6%. See ETR Attachment 6, p. 1. There were expenditure spikes in 2005, 2011 and 2012, which correspond with some of the underground events. *Id.* at p. 2. These cost spikes indicate that some remediation was performed to address the incidents. However, I would have expected to see an increase in the per mile underground costs to mitigate future network events, which I did not find.

Q. In the course of your analysis did you discover any industry averages or reports that would put IPL's underground maintenance cost per mile in perspective?

A. Yes. I found several reports that contrasted the costs of overhead distribution plant with underground distribution plant. The reports that I reviewed are:

- "Cost-Benefit Evaluation of Underground versus Overhead Power Lines", prepared by Power System Engineering, Inc., dated July 6, 2010.
- "Underground vs. Overhead: Power Line Installation-Cost Comparison and Mitigation", Power Grid International, authors Frank Alonso and Carolyn A.E. Greenwell, SAIC, dated February 1, 2013.
- "Economic Implications of Buried Electric Utilities", Marbek Resource Consultants, dated March 21, 2007.
- "The Feasibility of Placing Electric Distribution Facilities Underground." Report of the Public Staff to the North Carolina Natural Disaster Preparedness Task Force, dated November 2003.

These reports concentrated on the construction and societal cost of overhead distribution plant in contrast to underground distribution plant, with limited data regarding the O&M cost variations. Some of the points highlighted the differences in cost: while there were fewer outages with underground distribution plant, those outages tended to last longer. In addition, the analysis found that the useful life of underground plant averaged 30 years, while overhead plant averaged 50 years. The latter point is borne out by the 2013 Depreciation Study prepared for IPL and filed in this Cause, which showed that the estimated remaining useful life of the underground conductors and devices (FERC account 367) averaged 22.3 years, while the life of overhead conductors and devices averaged (FERC account 356) 33.1 years.

Q. Were you able to discover comparable underground plant O&M cost per mile ratios to assess IPL's underground plant O&M costs incurred per distribution underground mile over a similar period?

A. The North Carolina report listed above contained cost per mile ratios for the year 2003. I prepared ETR Attachment 7, comparing IPL's O&M costs per underground distribution mile for the period 2007 to 2014 with the 2003 cost per mile detailed in the North Carolina report, which was prepared by the North Carolina Public Staff of the Utilities Commission. The report was prepared in conjunction with an earlier investigation into a December 2002 Ice Storm by the Utilities Commission and Public Staff. The Commission and Public Staff were seeking to determine whether or not electric facilities should be placed underground to avoid widespread outages during major storms. While the information contained within the North Carolina report is not directly on point, it does provide some information relative to underground plant O&M North Carolina expenses. By reference to ETR Attachment 7, there is a significant difference in the operation and maintenance costs per underground mile incurred by IPL: $802 per mile in 2007 and $798 per mile in 2014 and a high of $1,077 per mile in 2011, when compared to the average O&M cost per mile in the North Carolina report for duct bank urban underground of $4,052 per underground distribution mile and $920 per direct buried underground distribution mile. That same North Carolina report determined that the average cost of overhead O&M

per distribution mile was $917 per mile in 2003. By comparison, the IPL average cost per overhead mile was $1,898, more than twice the O&M cost it laid out and expended per underground mile.

While the time frames and demographics are different in Indiana than in North Carolina, and each utility is uniquely configured to serve its own designated service territory, the disparity in costs per distribution mile incurred by IPL between overhead and underground distribution plant warrants further investigation.

Q. Should IPL have spent more O&M dollars on underground distribution plant than it has historically spent?

A. It is premature to say. I do not believe that any firm conclusions or opinions can be completely developed based on cost information discussed above. The cost data should be analyzed in conjunction with any engineering data developed in reviewing the numerous manhole events. If the engineering reports support the O&M efforts of IPL, then the costs incurred were appropriate. If the engineering reports suggest that the operation and/or maintenance efforts of IPL were not adequate to minimize the manhole events, then obviously the expenses incurred and actions taken by IPL were inadequate.

The cost data discussed in my testimony only examines what was actually spent by IPL and how it compares to previous years' expenditures. Standing alone it only addresses trends; and it does not address whether the funds expended were adequate or not to mitigate the network events that eventually occurred.

VI. RECOMMENDATIONS

Q: What does the OUCC recommend in this proceeding?

A: The OUCC recommends the following:

- Approve the future depreciation accruals proposed by IPL for those accounts that have a negative net utility plant in service balance at December 31, 2013. Reevaluate such accruals in IPL's next rate case or no later than five years hence, whichever comes first.
- Utilize the $77,634,282 (see ETR Attachment 1) of net negative plant in service balances (derived from the Electric Distribution Plant accounts at December 31, 2013) to cover necessary expenditures to remediate the manhole and explosion events within the IPL distribution system.
- Require IPL to document how and why the 1.6% increase in maintenance cost per mile (over twenty (20) years) is sufficient to maintain IPL's underground network.
- Require that any future "lost revenue" recovery calculation based on the Commission's Order in Cause 44497, subsequent Orders or legislation reflect any fixed cost recovery already recovered through the customer charge and first block of the energy charge for all customers.
- Require IPL to provide a new depreciation study in IPL"s next rate case or no later than five years hence, whichever comes first.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A

Q: Please describe your educational background and experience.

A: I am a graduate of Drexel University in Philadelphia, PA, with a Bachelor of Science degree in Business Administration. I was employed by South Jersey Gas Company as an accountant responsible for coordinating annual budgets, preparing preliminary monthly, quarterly, annual and historical financial statements, assisting in preparation of annual reports to shareholders, all SEC filings, state and local tax filings, all FPC/FERC reporting, plant accounting, accounts payable, depreciation schedules and payroll. Once the public utility holding company was formed, South Jersey Industries, Inc., I continued to be responsible for accounting as well as for developing the consolidated financial statements and those of the various subsidiary companies including South Jersey Gas Company, Southern Counties Land Company, Jessie S. Morie Industrial Sand Company, and SJI LNG Company.

I left South Jersey Industries, Inc. and took a position with Associated Utility Services Inc. (AUS), a consulting firm specializing in utility rate regulation including rate of return, revenue requirement, purchased gas adjustment clauses, fuel adjustment clauses, revenue requirement development and valuation of regulated entities.

On leaving AUS, I worked as an independent consultant in the public utility area as well as telecommunications including cable television (CATV). I joined the OUCC in December 2012 as a utility analyst.

Q: Have you previously testified before the Indiana Utility Regulatory Commission?

A: I have previously testified before the Indiana Utility Regulatory Commission (Commission) in Cause Nos. 44311, 44331, 44339, 44363, 44370, 44418, 44429, 44446, 44478, 44486, 44495, 44497, 44526, 44540, 44542 and 43955 DSM-2. I have also testified before the regulatory commissions in the states of New Jersey, Delaware, Maryland, Pennsylvania, New York, Connecticut, Georgia, Florida, North Carolina, Ohio, Oklahoma, Virginia and Wisconsin. In addition to the states mentioned, I submitted testimony before the utility regulatory commissions in the Commonwealth of Puerto Rico and the U.S. Virgin Islands. I have also testified as an independent consultant on behalf of the U.S. Internal Revenue Service in Federal Tax Court, New York jurisdiction.

Q: What did you do to prepare your direct testimony in this Cause?

A: I reviewed and analyzed the petition, pre-filed testimony, exhibits, workpapers, and data request responses of Indianapolis Power & Light Company ("IPL"). I also attended meetings with IPL employees to discuss maintenance policies and procedures at the IPL generation facilities and the development of the "fair value" rate base in this proceeding.

IPL
NEGATIVE PLANT IN SERVICE ACCOUNTS
PER DEPRECIATION STUDY

ACCOUNT NO.	ACCOUNT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	NET ORIGINAL COST	FUTURE ACCRUALS	FUTURE BOOK RESERVE	RATIO
311	STRUCTURES & IMPROVEMENTS EV	$20,592,680	$22,814,593	($2,221,913)	$6,015,159	$28,829,752	140.00%
312	BOILER PLANT EQUIPMENT EV	59,082,018	67,682,591	(8,600,573)	15,032,234	82,714,825	140.00%
312.3	ASH & COAL HANDLING EQUIPMENT EV	7,401,672	8,329,854	(928,182)	2,032,487	10,362,341	140.00%
312.31	ASH & COAL HANDLING EQUIP. MPP HS	4,610,527	5,027,291	(416,764)	597,551	5,624,842	122.00%
314	TURBOGENERATOR UNITS EV	30,765,322	34,489,834	(3,724,512)	8,581,616	43,071,450	140.00%
315	ACCESSORY ELECTRIC EQUIPMENT EV	7,590,904	10,627,265	(3,036,361)	0	10,627,265	140.00%
315	ACCESSORY ELECTRIC EQUIPMENT HS	277,082	338,040	(60,958)	0	338,040	122.00%
316	MISCELLANEOUS POWER PLANT EQUIP. EV	1,446,381	1,778,705	(332,324)	246,228	2,024,933	140.00%
316	MISCELLANEOUS POWER PLANT EQUIP. HS	115,116	128,824	(13,708)	11,618	140,442	122.00%
344	GENERATORS EV	324,512	379,679	(55,167)	0	379,679	117.00%
344	GENERATORS PETERSBURG	931,147	1,080,130	(148,983)	0	1,080,130	116.00%
364	POLES, TOWERS & FIXTURES	131,119,431	166,475,225	(35,355,794)	95,763,636	262,238,861	200.00%
365	OVERHEAD CONDUCTORS AND DEVICES	174,922,561	202,584,729	(27,662,168)	129,768,136	332,352,865	190.00%
371	INSTALLATIONS ON CUSTOMER PREMISES	37,596,022	52,212,342	(14,616,320)	4,181,691	56,394,033	150.00%
373	STREET LIGHTING & SIGNAL SYSTEMS	62,312,128	71,033,018	(8,720,890)	625,929	71,658,947	115.00%
	TOTAL RE: DEPRECIATION STUDY	$539,087,503	$644,982,120	($105,894,617)	$262,856,285	$907,838,405	168.40%

INDIANAPOLIS POWER LIGHT COMPANY
EXAMPLE OF FIXED COSTS
RECOVERED THROUGH RS TARIFF

DESCRIPTION	AMOUNT
PER IPL ACOSS: (CONFIDENTIAL WORKPAPER 1.0)	
PROPOSED REVENUE REQUIREMENT:	
RESIDENTIAL TARIFF RS:	
DEMAND	$308,052,879
CUSTOMER	71,540,429
TOTAL FIXED COSTS	379,593,308
ENERGY	7,744,477
FUEL	159,315,107
TOTAL REVENUE REQUIREMENT	$546,652,892
PER IPL PROPOSED REVENUE (PETITIONER'S WITNESS JSG WORKPAPER 2.0)	
CUSTOMER CHARGE	$82,103,606
FIRST USAGE BLOCK 500 KWH	210,477,070
SUB TOTAL	292,580,676
LESS:	
FUEL IN FIRST USAGE BLOCK	70,717,818
REVENUE AVAILABLE TO RECOVER FIXED COSTS	221,862,858
PERCENTAGE OF FIXED COSTS RECOVERED IN CUSTOMER CHARGE AND FIRST USAGE BLOCK	58.45%
DEVELOPMENT OF FUEL COST:	
FUEL COST/PER KWH (PETITIONER'S WITNESS JSG-WORKPAPER 3.0, PAGE 1 OF 1)	$0.031561
KWH IN FIRST USAGE BLOCK	2,240,671,009
FUEL COST IN FIRST USAGE BLOCK	$70,717,817.72

INDIANAPOLIS POWER LIGHT COMPANY
STEAM PRODUCTION PLANT FAIR VALUE
COMPARISON OF RESULTS UNDER DIFFERENT DISCOUNT RATES

IPL DISCOUNT RATE USED INCLUDING PROPERTY TAX	OUCC SELECTED DISCOUNT RATES	EAGLE VALLEY WORKPAPER 14 DCF VALUE	GEORGETOWN WORKPAPER 15 DCF VALUE	HARDING STREET-STEAM WORKPAPER 16 DCF VALUE	HARDING STREET-GAS WORKPAPER 17 DCF VALUE	PETERSBURG WORKPAPER 18 DCF VALUE	TOTAL STEAM PRODUCTION DCF VALUE
9.73% - 10.28%		($38,473,248)	$80,357,061	$69,001,247	$175,465,447	$790,298,677	$1,076,649,184
	15.00%	($34,201,346)	$50,018,097	$6,721,769	$118,258,279	$422,561,611	$563,358,410
	16.00%	($33,470,002)	$46,010,150	($1,956,074)	$109,774,682	$373,914,006	$494,272,762
	17.00%	($32,761,428)	$42,474,176	($9,540,707)	$102,179,145	$331,801,093	$434,152,279
	18.00%	($32,074,713)	$39,339,946	($16,181,001)	$95,353,976	$295,172,232	$381,610,440

NOTE:

The above data is based on the information provided in IPL Workpapers 14 - 18, IPL Witness JJR Attachment 2.

The Property Tax Rate for each property used by IPL Witness John J. Reed ranges from 1.26% - 1.80%

IPL
NEGATIVE PLANT IN SERVICE ACCOUNTS
PROPOSED ANNUAL DEPRECIATION ACCRUAL ADJUSTMENT

ACCOUNT NO.	ACCOUNT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	NET ORIGINAL COST	IPL CALCULATED ANNUAL ACCRUAL	OUCC PROPOSED ANNUAL ACCRUAL
311	STRUCTURES & IMPROVEMENTS EV	$20,592,680	$22,814,593	($2,221,913)	$2,416,749	$1,208,375
312	BOILER PLANT EQUIPMENT EV	59,082,018	67,682,591	(8,600,573)	6,089,945	3,044,973
312.3	ASH & COAL HANDLING EQUIPMENT EV	7,401,672	8,329,854	(928,182)	826,774	413,387
312.31	ASH & COAL HANDLING EQUIP. MPP HS	4,610,527	5,027,291	(416,764)	256,459	128,230
314	TURBOGENERATOR UNITS EV	30,765,322	34,489,834	(3,724,512)	3,496,082	1,748,041
315	ACCESSORY ELECTRIC EQUIPMENT EV	7,590,904	10,627,265	(3,036,361)	0	0
315	ACCESSORY ELECTRIC EQUIPMENT HS	277,082	338,040	(60,958)	0	0
316	MISCELLANEOUS POWER PLANT EQUIP. EV	1,446,381	1,778,705	(332,324)	99,037	49,519
316	MISCELLANEOUS POWER PLANT EQUIP. HS	115,116	128,824	(13,708)	5,008	2,504
344	GENERATORS EV	324,512	379,679	(55,167)	0	0
344	GENERATORS PETERSBURG	931,147	1,080,130	(148,983)	0	0
364	POLES, TOWERS & FIXTURES	131,119,431	166,475,225	(35,355,794)	2,735,168	1,367,584
365	OVERHEAD CONDUCTORS AND DEVICES	174,922,561	202,584,729	(27,662,168)	3,917,632	1,958,816
371	INSTALLATIONS ON CUSTOMER PREMISES	37,596,022	52,212,342	(14,616,320)	176,955	88,478
373	STREET LIGHTING & SIGNAL SYSTEMS	62,312,128	71,033,018	(8,720,890)	19,901	9,951
	TOTAL RE: DEPRECIATION STUDY	$539,087,503	$644,982,120	($105,894,617)	$20,039,710	$10,019,855

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY (IPL) FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE, FOR APPROVAL OF NEW SCHEDULES OF RATES, RULES AND REGULATIONS, FOR AUTHORITY TO CONTINUE THE CAPITALIZATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION AND TO DEFER DEPRECIATION EXPENSE ON IPL'S STOUT COMBUSTION TURBINE UNIT #5, FOR AUTHORITY TO REFLECT THE ADDITION TO THE FAIR VALUE OF IPL'S UTILITY PROPERTY OF THE FAIR VALUE OF IPL'S ENVIRONMENTAL COMPLIANCE CAPITAL PROJECTS AND QUALIFIED POLLUTION CONTROL PROPERTY UNDER CONSTRUCTION PURSUANT TO IC 8-1-27-19 AND IC 8-1-2-6.6 AND FOR APPROVAL OF REVISED DEPRECIATION RATES.	CAUSE NO. 39938

PETITIONER'S PRE-FILED TESTIMONY AND EXHIBITS

VOLUME VI

TSL Petitioner's Exhibit TSL--consisting of the testimony of Thomas S. LaGuardia, including Exhibits TSL-1 and TSL-2.

DSR Petitioner's Exhibit DSR--consisting of the testimony of Donald S. Roff, including Exhibits DSR-1 through DSR-8.

PETITIONER'S EXHIBIT TSL
I.U.R.C. Cause No. 39938

INDIANAPOLIS POWER & LIGHT COMPANY
1994 ELECTRIC RATE CASE

THOMAS S. LAGUARDIA
PRESIDENT
TLG SERVICES, INCORPORATED

DIRECT TESTIMONY
ON
DISMANTLING COSTS

SPONSORING
PETITIONER'S EXHIBITS TSL-1 AND TSL-2

PRE-FILING DATE: TUESDAY, OCTOBER 11, 1994
PUBLIC HEARING DATE: TUESDAY, FEBRUARY 7, 1995

THOMAS S. LAGUARDIA
INDIANAPOLIS POWER & LIGHT COMPANY
1994 ELECTRIC RATE CASE

IPL is seeking an increase in rates through depreciation reserves to recover the costs of dismantling its fossil-fueled power plants at the end of their useful lives. Dismantling cost estimates were prepared for the H.T. Pritchard, E.W. Stout and Petersburg power stations and included the costs of Engineering Planning and Preparations, Dismantling and Site Restoration. The total costs for each station are $26.1 million for Pritchard, $32.5 million for Stout and $63.6 million for Petersburg. The costs were prepared in 1993 dollars and include an average contingency of 15.6% to allow for the costs of high probability project problems that are likely to occur in dismantling but where the occurrence, duration and severity cannot be accurately predicted and have not been included in the basic estimate. The costs include credit for scrap recovery which offsets the dismantling costs.

Upon retirement of the last unit at each station, the facility may either be rendered safe indefinitely (through on-going maintenance, repair and security measures), or dismantled. The costs to maintain the retired units in a safe manner is greater than the current costs to dismantle the units. Accordingly, it is recommended to dismantle the stations at the end of their useful lives.

Petitioner's Exhibit TSL
I.U.R.C. Cause No. 39338

DIRECT TESTIMONY OF THOMAS S. LAGUARDIA
PRESIDENT
TLG SERVICES, INCORPORATED

Q1. Please State Your Name And Business Address.

(a) Thomas S. LaGuardia, 148 New Milford Road East, Bridgewater, CT 06752

Q2. What Is Your Occupation?

(a) I am President of TLG Services, Inc. (TLG)

Q3. What Is The Business Of TLG?

(a) TLG provides engineering and field services for nuclear and fossil-fueled generating stations.

Q4. What Are Your Responsibilities With TLG?

(a) I am responsible for the technical and business management of engineering and field services in the areas of decontamination, decommissioning, waste management and general engineering for nuclear and fossil-fueled generating stations.

Q5. What Is Your Educational And Professional Background?

(a) I completed my Bachelor of Science in Mechanical Engineering at Polytechnic Institute of Brooklyn in 1962 and my Master of Science in Mechanical Engineering at the University of Connecticut in 1968. I am a registered Professional Engineer in Connecticut (No. 10393), New York (No. 059389) and New Jersey (No. 38193). I founded TLG in April, 1982. I was employed by Nuclear Energy Services in Danbury, Connecticut, from 1973 until I founded TLG. My prior employment was with Gulf Nuclear Fuels Corporation (formerly United Nuclear Corporation [UNC]) and Combustion Engineering.

Q6. What Is the Purpose Of Your Testimony?

(a) I am presenting the results of the dismantling cost studies prepared by TLG in 1993 dollars for the following fossil-fueled power plants owned by Indianapolis Power & Light Company (IPL):

Station	No. of Units	Station Megawatts
H.T. Pritchard	6	364 MWe
E.W. Stout	7	778 MWe
Petersburg	4	1713 MWe

The testimony includes the dismantling cost and schedule estimates, and a discussion of dismantling techniques.

Q7. Do You Have Experience In The Design And Construction Of Fossil-Fueled Generating Stations?

(a) Yes. During my employment with Combustion Engineering, Inc. from 1962 to 1968, I was a boiler design, performance and construction engineer for 500 megawatt electric (MWe) coal fired power boilers, and merchant and Naval oil fired marine boilers.

Q8. What Is Covered By The Term "Decommissioning" As Used With Reference To Generating Stations?

(a) Decommissioning is the planned and orderly retirement of a generating station. In the case of nuclear plant decommissioning, it requires the complete removal and controlled disposal of radioactive materials to levels prescribed by the U.S. Nuclear Regulatory

Commission (NRC), and termination of the NRC license. The utility may then disposition the remaining clean systems and structures in the same manner as a fossil-fueled power plant.

In the case of a fossil-fueled power plant, upon retirement the facility may either be rendered safe indefinitely (through on-going maintenance, repair and security measures), or dismantled. A specific discussion of public safety and dismantling is included later in this testimony.

Q9. What Decommissioning Experience Do You Have?

(a) My decommissioning experience began as site representative for UNC during the BONUS reactor decommissioning in 1969 and 1970. BONUS was a 17 MWe demonstration power reactor located in Puerto Rico, owned by the U.S. Atomic Energy Commission (USAEC), now the U.S. Department of Energy (USDOE), and operated by the Puerto Rico Water Resources Authority. It was the largest reactor decommissioned by entombment up to that time. The program involved extensive chemical decontamination of radioactive systems, selective piping and component removal, and entombment of the reactor vessel within a massive concrete barrier. The entombment has a design life of 125 years. My role as site representative was to act as a technical liaison and provide project engineering and schedule management assistance during system decontamination, component removal, vessel entombment and facility closeout.

Following the BONUS program, I was lead engineer for UNC during the Elk River Reactor decommissioning between 1970 - 1974. Elk River was a 20 MWe demonstration power reactor located in the state of Minnesota, owned by the USAEC and operated by United Power Association. Elk River was decommissioned by complete dismantling. The program involved segmentation of the reactor vessel and internals using remotely operated cutting torches, as well as the packaging, shipping and controlled burial of the segments.

Similarly, radioactive piping and components were removed, packaged, shipped and buried. Radioactive concrete was demolished by controlled blasting, and nonradioactive concrete demolished by wrecking ball to completely dismantle the facility. Initially, my role for UNC was Consulting Engineer and later Lead Engineer for UNC technical support for on-site activities.

I was Project Engineer for the detailed engineering and planning of the Shippingport Station Decommissioning Project from 1979 - 1982. Shippingport was a 72 MWe light water breeder reactor located in the state of Pennsylvania, owned by the USDOE and operated by Duquesne Light Company. The facility is now dismantled, and TLG, with its joint venture partner, Cleveland Wrecking Company, dismantled all of the clean and contaminated piping and components and removed contaminated concrete. My role for TLG/Cleveland was Project Director, and I selected and managed an on-site project management team to hire and supervise work crews to accomplish the dismantling. Our work is complete and was performed on schedule and within budget.

I also assisted Atomic Energy of Canada, Ltd. in the detailed engineering and planning for the decommissioning of the 238 MWe Gentilly Unit 1 reactor located in Three Rivers, Canada. My role was to provide overall decommissioning consulting services and detailed cost estimation of alternatives.

Q10. Have You Prepared Or Co-authored Any Studies And Reports On Decommissioning Cost Estimating And Technology?

(a) Yes. While at Nuclear Energy Services, I was Principal Investigator for the Atomic Industrial Forum National Environmental Studies Project (NESP) decommissioning study entitled "An Engineering Evaluation of Nuclear Power Reactor Decommissioning Alternatives" (AIF/NESP-009). This study evaluated the costs, schedules and environmental impacts of decommissioning 1100 MWe reactors (Pressurized Water Reactors [PWRs], Boiling Water Reactors [BWRs], and High Temperature Gas Reactors [HTGRs]).

I also co-authored the "Decommissioning Handbook" for the USDOE. The Handbook reported the state-of-the-art in decommissioning technology (as of 1980), including decontamination, piping and component removal, vessel segmentation, concrete demolition, cost estimating and environmental impacts.

At TLG, I co-authored "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates" (AIF/NESP-036) for the Atomic Industrial Forum, National Environmental Studies Project. The Guidelines identify the elements of costs to be included in the estimation of decommissioning activities for each of the principal decommissioning alternatives. Specific guidance in cost estimating methodology and reference cost data is provided in this study. Themajor objective of this study is to provide a basis for consistent cost estimating methodology.

TLG also prepared a study, which I co-authored, entitled, "Identification and Evaluation of Facilitation Techniques for

Decommissioning Light Water Power Reactors" (NUREG/CR-3587) for USNRC. The study evaluated the costs and benefits of techniques to reduce occupational exposure and waste volume from decommissioning. In addition, TLG prepared the Decommissioning Plans (DP) for Dresden Unit 1, Pathfinder and Cintichem reactors, and the Environmental Reports (ER) for Dresden Unit 1 and Indian Point Unit 1. TLG personnel authored the paper "How to Determine the Cost of Dismantling a Fossil-Fuel Electric Power Plant," A. Carlstrom, Cost Engineering Magazine, April, 1989.

Under my supervision and direction, TLG has prepared site-specific decommissioning studies for most of the nuclear units in the United States and 43 fossil-fueled power plants. TLG was responsible for overseeing the dismantling and demolition of a fossil-fueled steam plant for a major Connecticut hospital facility. In connection with this demolition project, I participated in the site inspection and cost estimate development. The work was subcontracted and TLG personnel supervised the contractors.

Q11. For What Utilities Has TLG Prepared Site-Specific Dismantling Studies Of Fossil-Fueled Power Plants?

(a) In addition to the IPL study, TLG has prepared site-specific dismantling studies for fossil-fueled power plants owned by:

Allegheny Power System Inc.	Kansas City Power & Light Co.
Texas Utilities Co.	Public Service Electric & Gas Co.

These studies included plants ranging in power levels from 40 to 750 MWe per unit.

Q12. Are You Aware Of Any State Utility Regulatory Commission Which Has Adopted Fossil-Fueled Power Plant Dismantling Cost Estimates As Part Of The Commission Regulatory Policy?

(a) Yes. The Florida Public Service Commission in Docket No. 890186-E1, adopted a policy requiring investor-owned utilities to provide updated dismantling studies for their review once every four years in connection with each utility's depreciation study. Specific dismantling cost estimates prepared by each utility were adopted for Tampa Electric Company, Gulf Power Company, Florida Power Corporation and Florida Power & Light Company.

Q13. What Type Of Costs Are Analyzed In A Dismantling Study?

(a) There are three types of costs included and analyzed in a dismantling study: activity-dependent costs, period-dependent costs and collateral costs. Activity-dependent costs are those associated with the physical work of removing piping, components and structures and transporting and disposing of the same. These costs represent labor, materials and special services (subcontracted) costs associated with the work crews activities (hence, activity-dependent costs). The summation of the durations to perform these activities when properly sequenced provides the overall schedule for the project.

Period-dependent costs are those associated with the management staff costs which are necessary to provide technical and administrative direction to the project. These management costs must continue for the duration of the project. The project is divided into three periods: 1) Engineering Planning and Preparations; 2) Dismantling; and 3) Site Restoration. The management staff size is adjusted to reflect the crew size and work activities in each period. Accordingly, these staff costs are period-dependent.

Collateral costs are all those costs which are neither activity- nor period-dependent. They include insurance, taxes, permits, large equipment purchases and special tools.

Q14. What Are The Major Differences Between Nuclear And Fossil Power Plants?

(a) The major difference is the radioactivity contained in nuclear power plants. Removal of radioactively contaminated piping, components and structures from a nuclear plant is more difficult and costly than for comparable items from a fossil plant. The activities of decontaminating, removing, packaging, shipping and burying radioactive materials from a nuclear plant require strict radiological controls, special containments and packaging, and licenses for the transport for disposal. There are many more opportunities for problems to arise in nuclear plant decommissioning than in fossil plants.

Fossil plants have no radioactivity, and so dismantling is comparable to reverse construction. There are fewer potential hazards for the worker and so productivity is higher overall than nuclear plants, and the overall potential for problems is lower.

Q15. Does Your Experience In The Decommissioning Of Nuclear Power Plants Aid In The Conduct Of A Site-Specific Dismantling Study Of A Fossil-Fueled Power Plant?

(a) Yes. The parallelism in approach between nuclear plant decommissioning and fossil plant dismantling enables us to rely on the field experience from nuclear decommissioning to prepare fossil plant studies. In particular, the following major areas of planning and estimating exhibit similar characteristics.

1. Site Characterization

The process and planning for identification of radionuclide contamination composition and extent for nuclear power plants is similar to that required for potentially hazardous materials in fossil-fueled power plants.

2. Removal of Hazardous Material (Asbestos)

Planning and removal of asbestos-containing materials in nuclear and fossil plants is identical.

3. Sequencing of Work Activities

Identification and sequencing of essential (to the decommissioning task) and non-essential systems removal follows the same considerations in both types of plants. Essential systems include electric power, lighting, heating, ventilation and liquid processing systems. For example, power and lightning would be retained as long as possible to avoid bringing in temporary services prematurely.

4. Management Staff

Identification of utility and decommissioning (dismantling) staffing composition and levels follows the same process in both types of units. The specific job functions will differ but the logic is the same. Management staff costs are period-dependent; that is, they are a function of the overall project duration.

5. Removal of Non-Contaminated Equipment/Structures

Removal of non-contaminated piping, components and structures are activity-dependent. The methods for their removal are identical for most of the systems and structures in each type of plant. Piping diameters and lengths are essentially identical (size-for-size plants), and the removal rate will be the same. Clean components, such as feedwater heaters and pumps, condensate pumps, demineralizer systems, etc., in nuclear plants, are the same sizes and types found in fossil plants. Steel and concrete structures are removed in the same manner in both types of plants. Removal of equipment unique to fossil plants, such as coal handling and air cleaning systems, relates to the weight of sub-components, and is accomplished by rigging and segmentation.

6. <u>Scheduling</u>

The scheduling of work activities for either type of plant follows the proven planning techniques of activity precedence networks and critical path management. An activity precedence network is a flow diagram of sequenced activities based upon the priority or "precedence" of completing one or more activities before starting another activity. The critical path is the longest sequence of work activities in a precedence network from project initiation to completion.

7. <u>Collateral Cost</u>

Collateral costs are neither activity-dependent nor period-dependent costs. They include items such as engineering, energy, licenses, permits, and taxes, etc. These items are identical in both types of plants, although specific cost values will differ.

8. <u>Contingency</u>

Contingency as described more completely later in this testimony, is a cost allowance for field-related problems that are likely to occur. These problems include tool and equipment breakdown, late deliveries of supplies and equipment, and adverse weather. These field problems occur in both nuclear and fossil plant dismantling, although the specific allowances differ in each case.

9. Field Experience

The field experience in both nuclear and fossil plant dismantling for clean equipment is essentially identical. Heavy lifts of components weighing 50 to 450 tons are common in both plant types, and the planning and implementation activities are virtually identical.

In summary, the nuclear plant decommissioning experience is directly applicable to fossil plant dismantling.

Q16. How Does This Estimating Process Differ From Construction Estimating?

(a) There is very little difference in the elements of cost between fossil plant dismantling and construction. Both activities must account for labor, materials, equipment, services and collateral costs (as defined earlier). The activities related to construction are similar to those for dismantling. Specifically, construction activities such as rigging components into position and welding connecting piping are comparable to dismantling activities such as cutting connecting piping and rigging components out of the structures. In the case of construction however, the pipe welds must be inspected by nondestructive methods (such as X-Ray examination), and cut out and re-welded if flaws in the weld are identified. This re-work causes schedule delays and incurs additional expense. In the case of dismantling, the pipe need only be cut once. Problems in dismantling occur when plant drawings and specifications do not properly reflect the plant as constructed. This occurs when changes to the plant are made that have not been recorded on the as-built drawings. This can result in additional dismantling costs. However, in general dismantling estimating is comparable to construction cost estimating.

Q17. Please Describe The Document Which Has Been Marked For Identification As Petitioner's Exhibit TSL-1.

(a) Petitioner's Exhibit TSL-1 is a copy of the dismantling study report relating to the IPL power plants prepared by TLG.

Q18. Was The Dismantling Study Prepared Under Your Direction And Supervision?

(a) Yes. I developed the basic methodology used at TLG to estimate the costs to dismantle fossil-fueled power plants. I trained my engineering and estimating staff in this methodology.

With respect to the estimates prepared for IPL, I personally inspected each of the power stations with the TLG staff assigned to this project. This included an inspection of the boilers, turbine-generators, condensate and feedwater systems, and the fuel handling and pollution control systems. The purpose of these inspections was to familiarize myself and the TLG staff with the site-specific features of each unit so that the drawings and specifications used in the estimate would be better understood at the engineering offices of TLG. During the preparation of the cost estimate details, I provided guidance and interpretation to the TLG staff on how to estimate specific areas of the units. I reviewed the results of each plant cost estimate to ensure the results were reasonable and representative of the features of each unit. Finally, I supervised the preparation of the report summarizing the results of the estimate.

Q19. What Is The Purpose Of The Study?

(a) The purpose was to estimate the cost of dismantling the power stations in constant 1993 dollars so that this information could be provided to Deloitte & Touche for use in its depreciation study.

Q20. What Procedures Were Used For The Dismantling Studies?

(a) The studies were developed using the detailed engineering drawings, together with plant description and physical inventory documents. These drawings and documents were used to identify the general arrangement of each facility and to determine estimates of building concrete volumes, steel quantities, numbers and size of components and degree of site restoration required.

Selected reference boiler units were chosen to characterize all station boilers. The remainder of the site was characterized for each station. The combination of the number of each type of boiler plus the inventory of the remainder of the site provides a complete inventory of the station.

The TLG staff made site inspections of each plant. The on-site inspections included investigation of the access to remove components, and movement of heavy equipment (cranes, forklifts, front-end loaders) close to the structure for demolition and removal work.

Dismantling is a labor-intensive program. Representative labor rates for the state in which the plant is located and each craft or salaried work group are essential for development of a meaningful site-specific dismantling cost estimate. The TLG study used typical craft labor rates and utility salary data for the area provided by Mr. Max Califar, Vice President Human Resources for IPL. I consider the use of such labor cost information reliable and appropriate for the purposes of the dismantling study.

Q21. What Methodology Was Used To Prepare The Cost Estimate?

(a) The methodology used to develop the cost estimate followed the basic approach presented in the AIF/NESP-036 study report, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," the USDOE "Decommissioning Handbook" and American Association of Cost Estimators paper "A Methodology for Determining the Cost of Dismantling Fossil-Fueled Electric Power Plants." Obviously, nuclear power plant concerns are not necessary for fossil power plants and, therefore, none were included in the study. However, the basic methodology which is widely accepted by the electric power industry and regulatory commissions throughout the United States is applicable for fossil plants as well.

Q22. How Was This Methodology Applied To The IPL Plants?

(a) The aforementioned references use a unit cost factor method for estimating decommissioning activity costs to standardize the estimating calculations. Unit cost factors for activities such as concrete removal ($/cu yd), steel removal ($/ton), and cutting costs ($/in) were developed from the labor information provided. Consumable material and equipment rental costs (crane and truck rental, operating costs for heavy equipment, torch cutting gas consumption, etc.) was taken in large part from R.S. Means, "Building Construction Cost Data 1993." The activity-dependent cost for removal, shipping and disposal were estimated using the item quantity (cu yds, tons, inches, etc.) developed from plant drawings and inventory documents. The activity duration critical path derived from such key activities as boiler removal, turbine removal etc., was used to determine the total dismantling program schedule.

The program schedule is used to determine the period-dependent costs such as program management, administration, field engineering, equipment rental, and security. The salary and hourly rates are typical for personnel associated with period-dependent costs.

In addition, collateral costs were included for heavy equipment rental or purchase, safety equipment and supplies, energy costs, permits, taxes, and insurance.

The activity-dependent, period-dependent, and collateral costs were added to develop the total dismantling costs. An average 15.6% contingency was added to allow for the effect of unpredictable program problems on costs. Such a contingency is appropriate for a project of this size and type. The total dismantling costs plus contingency, less scrap credit provides the total project cost. One of the primary objectives of every dismantling program is to protect public health and safety. The cost estimate for the dismantling activities includes the necessary planning, engineering and implementation to provide this protection to the public.

Q23. For Purposes Of The Estimate, When Did You Assume The Units At Each Site Would Be Dismantled?

(a) We assumed dismantling of each unit would occur upon retirement of the last unit at each site. This approach is reasonable because it would be more difficult and costly to protect the operating units from potential damage when demolishing the retired units. Moreover, the dismantling staff and crew would only have to mobilize and demobilize once for the site instead of each time a unit is retired. Using the same staff and crew would take maximum advantage of the lessons learned as the units are dismantled in sequence.

Q24. How Was Scrap Or Salvage Credit Included In the Overall Estimate?

(a) Credit for carbon steel, stainless steel and copper scrap was included in the overall estimate based on current published scrap values.

No credit was included for salvage of any components, as these components will be of an obsolete design by the time these plants are dismantled. The labor cost to recover potentially salvageable materials (valves, pumps, motors, etc.), and to store, protect, package and ship them is not warranted. These materials were considered as scrap.

Q25. Please Describe The Process Of Dismantling A Fossil Power Plant And How That Process Was Reflected In The IPL Study.

(a) Approximately three months prior to final shutdown, engineering and planning would begin on the preparation of the Dismantling

Engineering Plan (Plan) and Environmental Report (ER). The Plan describes the status of the facility at shutdown, work to be accomplished, safety analyses associated with each of the major activities, general procedures and sequence to be followed, and final site condition upon completion of all work. Similarly, the ER would evaluate environmental effects to workers and the public, and waste generation effects on the site and environment. These documents would be submitted to the Environmental Protection Agency and other applicable regulatory agencies for review and approval, and authorization to proceed.

The sequence of work would be as follows:

Period 1 - Site Preparations - would begin upon shutdown of the facility, and would involve site preparations to initiate dismantling. All fuel is assumed to have been burned prior to shutdown.

Period 2 - Dismantling Operations - would begin upon receipt of approval of all regulatory agencies. This phase of the work involves the removal of all components of the boiler, air quality treatment systems (electrostatic precipitators, flue gas desulfurization systems, etc.), fuel handling systems (coal conveyors, crushers, oil storage tanks, etc.), the turbine-generator, condensate and feedwater systems. In general, the boiler will be dismantled in a bottoms-up mode, whereby the lower sections of the boilers will be cut at grade level, and remaining upper sections lowered to grade or scaffolding erected to cut the upper sections of the boiler furnace. This method of dismantling is necessary for the top-hung type of boiler that is supported from the steel structure.

Care must be taken to ensure sections are removed uniformly from the bottom to avoid any unbalanced load on the steel structure that may cause it to become unstable.

IPL has conducted a selective asbestos removal program at each of its fossil-fueled power plants. Accessible friable asbestos insulation will be removed by the IPL operating plant staff as it is encountered during routine maintenance activities. Non-friable, inaccessible asbestos will remain until the units are retired. The TLG study did not account for the cost for removal of asbestos during the selective removal program. The TLG study does include the cost of the residual asbestos removal as part of the dismantling work. Estimates provided by the IPL plant staff indicate that the Petersburg Unit 1 components contain asbestos insulation in systems in amounts ranging from 80% to 100%. Unit 2 components have much lower levels of asbestos insulation (approximately 25%). Units 3 and 4 have no asbestos. The Stout

Units 1-6 have varying percentages of asbestos on components ranging from 10% to 100%. Stout Unit 7 has no asbestos. Pritchard Units 1-6 have varying levels of asbestos ranging from 30% to 80%. The TLG dismantling cost estimates include the removal and disposal of these levels of asbestos insulation.
Steel structures used to support the boiler and turbine-generator components will be dismantled by controlled demolition (by lowering sections to grade by cranes) to prevent injury to workers on lower floors. The steel structures will be dismantled from the top down, essentially reversing the construction sequence.

Concrete structures such as boiler foundations, floors, turbine-generator pedestals and support buildings will be demolished by conventional wrecking methods. These may include the use of wrecking balls, pneumatically-operated rams on a backhoe, or controlled blasting.

Period 3 - Site Restoration - would involve the re-grading of all areas that were disturbed by the dismantling process. All structures will be removed to three feet below grade to permit re-vegetation of the site, or to eliminate at-grade hazards. Clean rubble would be used on site for fill and additional soil would be used to cover each subgrade structure. The site would be graded.

Q26. Is it Possible That Future Changes In Technology And Regulation Could Affect The Dismantling Costs?

(a) Yes. The TLG cost estimate prepared for these plants is based_on state-of-the-art technology. No provision is made to adjust for cost changes associated with changes in technology and regulations. It is my recommendation that IPL thoroughly review these estimates periodically and revise them, if necessary, to account for cost increases or decreases as influenced by future technology and regulations. It is my understanding that IPL intends to follow my recommendation.

Q27. What Is The Basis For The 15.6% Contingency?

(a) The purpose of the contingency is to allow for the costs of high probability program problems, where the occurrence, duration, and severity cannot be accurately predicted and have not been included in the basic estimate. The inclusion of contingency in cost estimation for both construction and dismantling is well accepted. The American Association of Cost Engineers (AACE) (in their Cost Engineers Notebook) defines contingency as follows:

> Contingency - specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur.

Past dismantling and decommissioning experience has shown that these problems are likely to occur and may have a cumulative impact.

Fossil-fueled and nuclear power plants share some of the same potential problems leading to the need for contingency in cost estimates. These problem areas include:

Schedule slippages -	leading to crew overtime payments and/or project extensions
Weather delays -	loss of productivity, overtime, slippages
Labor strikes -	loss of productivity, slippages
Workers injuries -	production interruptions, additional safety training, workers compensation claims, possible increased insurance premiums
Material shipping -	rescheduling of activities, inefficiencies in production, out-of-scope backcharges from subcontractors
Equipment breakdowns -	rescheduling of activities, inefficiencies in production, out-of-

	scope backcharges from subcontractors
Regulatory inspections -	insurance inspectors, Occupational Safety and Health Act (OSHA) inspectors, federal and state EPA inspectors, state building inspectors
Hazardous materials -	special handling requirements beyond planned requirements

Nuclear power plants additionally have to deal with the special handling requirements of radioactive materials for decontamination, removal, packaging, shipping and disposal. A more extensive discussion of nuclear contingency is included in the AIF/NESP-036 Guidelines Study (Chapter 13) referred to earlier.

In that study, individual contingencies ranged from 10% to 75%, depending on the degree of difficulty judged to be appropriate from our actual decommissioning experience. The overall contingency, when applied to the appropriate components of nuclear plant decommissioning costs, results in an average contingency of up to 25%.

For fossil plant dismantling, the absence of radioactive materials and their attendant potential problems simplifies the dismantling process. Individual activity contingency estimates for fossil-fueled power plants amount to an overall average of approximately 15% contingency.

Independent of our preparation of this estimate for IPL, R.S. Means, "Building Construction Cost Data 1993," suggests that a 15% contingency factor for conventional construction be used. This is consistent with the TLG recommendation.

Q28. How Does the 15.6% Factor You Used Compare To Contingency Factors Adopted By Regulatory Commissions For Nuclear Plant Decommissioning?

(a) As I discussed earlier, the nuclear contingency is generally 25%. The Federal Energy Regulatory Commission (FERC) adopted a 25% contingency for nuclear power plant decommissioning as reasonable, following the ruling of Judge Liebman in the Middle South Energy/Grand Gulf Case (Docket ER82-616), decision issued February 3, 1984. Numerous state public utility commissions have adopted a 25% contingency for nuclear plant decommissioning, as evidenced by an American Gas Association-Edison Electric Institute Depreciation Committee Survey, which showed that at least 21 of 32 utility survey respondents had included a 25% contingency in their estimates. The survey also showed that of the 15 utilities who filed rate cases, 11 had approval to use the 25% contingency for their plant decommissioning studies.

Q29. What Is the Feasibility Of The Dismantling Premise?

(a) There is extensive experience in the United States and in other countries for the complete dismantling of fossil power plants and related industrial facilities. This experience includes the dismantling of chemical refineries, steel mills, and nuclear power plants (with their associated non-nuclear turbine-generator portions). This directly related experience shows that the IPL plants can be completely dismantled safely.

Q30. Are There Any Regulations Or Codes Applicable To Dismantling?

(a) Yes. The Building Officials & Code Administrators (BOCA) National Building Code widely adopted by most states, including Indiana, requires that retired structures may not be left in an unsafe condition. Specifically, Section 120.1, "Right to Deem Unsafe," states:

> All buildings or structures that are or hereafter shall become unsafe, unsanitary or deficient in adequate means of egress facilities, or which

> constitute a fire hazard, or are otherwise dangerous to human life or the public welfare, or which involve illegal or improper use, occupancy or maintenance, shall be deemed unsafe buildings or structures. <u>All unsafe structures shall be taken down and removed or made safe and secure, as the code official deems necessary and as provided for in this section.</u> A vacant building, unguarded or open at door or window shall be deemed a fire hazard and unsafe within the meaning of this code.
>
> (Emphasis Added)

A retired power plant fits this definition of an unsafe structure which must be taken down and removed or made safe and secure.

Q31. Why Is Dismantling After A Power Plant Is Taken Out Of Service The Appropriate Alternative?

(a) Guarding retired power plants indefinitely is costly, requiring either a full-time guard force, or intrusion detection devices and alarms to local law enforcement agencies, and general building maintenance to maintain the structures in a safe condition. Furthermore, prompt dismantling of retired power plants makes the site available for alternative uses at the earliest possible time.

Q32. Have You Estimated The Costs Of Guarding And Maintaining These Power Plants For An Extended Period, As An Alternative To Dismantling Them?

(a) Yes. Using relatively straight-forward and reasonable assumptions, the total costs for security and maintenance for each unit over the storage period is clearly not cost-effective. As shown in Petitioner's <u>Exhibit TSL-2,</u> which was prepared by me, the annual security and maintenance costs are estimated to be $523,000. For an indefinite storage period of 1000 years, the cost per plant site would be $523.0 million. If the storage period were as short as 100 years, the cost would be $52.30 million. This latter cost is greater than either the Pritchard or Stout plant dismantling cost, and almost as great as the Petersburg Plant dismantling cost. At the end of the storage period, IPL would still have to dismantle these units at additional cost. Accordingly, there is no benefit to postpone the dismantling of these plants.

Q33. Is Reuse Of The Site For A Power Plant A Potential Use?

(a) Yes.

Q34. If The Site Could Be Reused, Why Couldn't The Power Plant Components Be Reused In Repowering?

(a) The designs of new generation power plants are not likely to use the same size and configuration of components, nor require the same type of building enclosures. Optimum facility design will be sized to match the megawatt size of a replacement power plant, if any, either larger or smaller. For example, new combustion turbine-generators are modular, self-contained units that don't need a building enclosure. Combined cycle units may require larger turbine buildings to enclose the waste heat steam generators which supply steam to the turbine. The cost to renovate older buildings and bring them to current safety code standards, combined with the less-than-optimum facility design makes reuse of the existing buildings an unlikely scenario. Furthermore, the existing components are likely to be of an obsolete design, more costly to operate and maintain and may not be compatible with new instrumentation and control systems.

Q35. Based On The TLG Study, What Do You Believe Are The Dismantling Costs Of The IPL Plants You Studied, In 1993 Dollars?

(a) I believe the dismantling costs are as follows:

COST SUMMARY*

	H.T. Pritchard	E.W. Stout	Petersburg
Base Dismantling Cost	$31,854,839	$43,244,432	$72,421,503
Contingency	5,080,376	6,763,829	11,020,095
Cost Subtotal	36,935,216	50,008,271	83,441,599
Scrap Credit	(10,872,095)	(17,474,367)	(19,833,992)
Total Project Cost	**$26,063,121**	**$32,533,904**	**$63,607,606**
Project Duration (months)	32.06	33.64	57.57

*Columns may not total due to rounding.

Q36. Why Does The Petersburg Station Cost More And Require A Longer Overall Project Duration Than The Pritchard Or Stout Station?

(a) The overall generating capacity (and therefore, size) of the Stout Station is twice as large as Pritchard, and Petersburg is twice as large as Stout. Accordingly, the cost to dismantle Petersburg is greater than that of Stout or Pritchard. Furthermore, the equipment inventory of Petersburg was substantially larger than Stout or Pritchard because Petersburg is a more recent design. As such, the overall duration to remove this larger inventory is greater than Stout or Pritchard.

Q37. Does This Conclude Your Prepared Direct Testimony?

(a) Yes.

EXHIBIT TSL-1

COST ESTIMATES
FOR DISMANTLING THE
H.T. PRITCHARD, E.W. STOUT & PETERSBURG
GENERATING STATIONS

Prepared For

INDIANAPOLIS POWER & LIGHT COMPANY
Indianapolis, IN

October, 1994

TLG SERVICES, INC.
Bridgewater, Connecticut 06752

TABLE OF CONTENTS

TABLE OF CONTENTS
(Continued)

Tables

Figures

Appendices

TABLE OF CONTENTS
(Continued)

EXECUTIVE SUMMARY

This report presents a summary of the estimated costs for the total dismantling of the H.T. Pritchard, E.W. Stout and Petersburg Generating Stations. These plants are owned and operated by Indianapolis Power & Light Company (IP&L). The stations are located in Martinsville, IN, Indianapolis, IN and Petersburg, IN, respectively.

The estimates include the cost of dismantling the turbine generators, fuel handling systems, air quality control systems and removal of all plant equipment. At the end of the dismantling activities, the plant sites will be in a condition such that the land will be available for alternative use.

This study provides the costs to dismantle each site under current regulatory requirements and using available technology. Total dismantling of all existing site structures is assumed. Total dismantling relieves the owner of the liabilities associated with leaving behind partially dismantled, potentially unsafe structures. Partial dismantling is not considered in this study. Partial removal of components and structures tends to make the overall process of dismantling more costly, with additional burdens of maintenance and security.

The study assumes dismantling is initiated immediately after final station shutdown. Delaying station dismantling for several years after shutdown can significantly increase the total dismantling cost. In a delayed dismantling mode, the utility continues to incur the cost of manning and maintaining the site in a protective storage state. In addition, at the end of the dormancy period the station must reactivate those systems necessary to support decommissioning operations and/or procure replacement services. Refurbishment activities could involve requalifying the cranes and other lifting devices, and reactivating electrical, lighting, air handling and other service systems. One of the biggest drawbacks to a delayed dismantling is the unavailability, at the time of final dismantling, of station operations personnel, whose knowledge of the station is invaluable in supporting and assisting decommissioning operations. Without personnel familiar with station operations, the dismantling program may incur additional costs as it compensates for engineering and planning developed from an incomplete data base.

The total costs, in 1993 dollars, are estimated to be $26,063,121, $32,533,904 and $63,607,606 for Pritchard, Stout and Petersburg, respectively.

The cost of dismantling of the boilers from bottom to top and the boiler structures from top to bottom are estimated using the unit cost factor method. TLG and IP&L used estimated quantities and volumes of the equipment and material to be removed during dismantling based on drawings and inventory documents. Unit cost factors were then applied to estimate activity-dependent costs. The period-dependent costs were then determined from a critical path schedule based on the removal activities.

The cost study includes removal and disposal of hazardous as well as non-hazardous waste materials including asbestos, fuel oils and non-PCB equipment oils.

Contingency was included in the estimate to address unforeseeable events that occur in a project of this nature. The contingency analysis, prepared on a line-item basis, is necessary to ensure the estimates reflect conditions likely to be encountered during dismantling.

In addition to estimated dismantling costs, the report includes estimated scrap quantities for each station.

The cost estimates for total dismantling, presented in 1993 dollars and including appropriate contingency, are summarized in Table 1.1. Detailed costs are discussed in Section 3. The anticipated project schedules are presented in Section 4.

1.0 INTRODUCTION

1.1 OBJECTIVE OF STUDY

The objective of this study is to present an estimate of the manpower, schedule, constant dollar costs and scrap credit for the total dismantling of the Pritchard, Stout and Petersburg fossil power stations at the end of their useful lives.

The study is not a detailed engineering document, but a cost estimate prepared in advance of the detailed engineering preparations which will be necessary to carry out the dismantling activities. The costs estimated in this study should be considered in light of this qualification.

The study recognizes that individual units at each site are retired at different times. However, it is assumed that dismantling of a given site will not occur until the last unit at that site is retired. The transition costs for security and maintenance on the units retired prior to final dismantling are not included in the study. Such costs are assumed to be an operational rather than a dismantling expense.

1.2 SITE DESCRIPTIONS

The H.T. Pritchard Station, shown in Figure 1.1, is a nominal 364 Mwe six-unit coal/oil-fired power plant located approximately 30 miles south of Indianapolis in Martinsville, IN. There is also a 2.75 Mw diesel generator at Unit 1. The original construction of the plant began in 1947 for Units 1 and 2. The power plant underwent major expansions to add Unit 3 in 1951, Units 4 and 5 in 1953 and Unit 6 in 1956. In 1989, an SO_3 injection system was installed on the roof of Unit 3. The buildings are primarily brick and reinforced concrete construction. For purposes of this study, it was assumed that the Pritchard Station would be retired in 2016.

The E.W. Stout Generating Station, shown in Figure 1.2, is a nominal 778 Mwe seven-unit coal/oil-fired power plant located in Indianapolis, IN. There is also a 2.75 Mw diesel generator at Unit 1, and Units 1, 2 and 3 each have a 20.0 Mw gas turbine for emergency use or to help meet peak demands. (Note: 80.0 Mw gas turbines are planned for installation at Units 4 and 5. These units are not included in this study.) The initial Units 1 & 2 structures were built in 1929. Unit 3 was added in 1941 with Unit 4 following in 1947. In 1958 Unit 5 was added with Unit 6 following in 1961. Unit 7, the largest unit, was added in 1973. Units 1-4 are brick buildings with reinforced concrete construction. The original roofing of built-up asbestos has been removed and replaced over the years with standard asphalt and/or rubber membrane roofing. Units 5 and 6 are generally brick and metal wall construction with metal siding. Their original asbestos built-up roofing has also been replaced. Unit 7 is a metal building with gravel roofing. Units 1 and 2 were retired in 1987. For purposes of this study, it was assumed that the Stout Station would be retired in 2021.

TABLE 1.1

STATION DISMANTLING COST AND SCHEDULE SUMMARY
(Note: Columns may not total due to rounding)

	Pritchard	Stout	Petersburg
Dismantling Activity Cost	$21,213,970	$32,454,555	$50,210,288
Period-Dependent Cost	$10,640,869	$10,789,887	$22,211,215
Subtotal	$31,854,840	$43,244,442	$72,421,503
Contingency	$ 5,080,376	$ 6,763,829	$11,020,095
Cost Subtotal	$36,935,216	$50,008,271	$83,441,599
Scrap Credit	($10,872,095)	($17,474,367)	($19,833,992)
Total Project Cost	**$26,063,121**	**$32,533,904**	**$63,607,606**
Project Duration (Months)			
Period 1	9.00	9.00	9.04
Period 2	21.88	21.45	47.38
Period 3	1.18	3.19	1.15
Total Duration	**32.06**	**33.64**	**57.57**

The Petersburg Generating Station is a nominal 1713 MWe four-unit coal-fired power plant located in Petersburg, IN. In addition, 2.75 Mw diesel generators are installed at Units 1, 2 and 3. The initial Unit 1 structure was completed in 1967, with Unit 2 completed in 1969, Unit 3 completed in 1977, and Unit 4 completed in 1986. Units 1 and 2 are uninsulated metal buildings with built-up roofing. Unit 3 is an uninsulated metal building with tar roofing and a small microwave penthouse. Unit 4 is an uninsulated metal building with a metal roof. For purposes of this study, it was assumed that the Petersburg station would be retired in 2029.

FIGURE 1.1
H.T. PRITCHARD GENERATING STATION

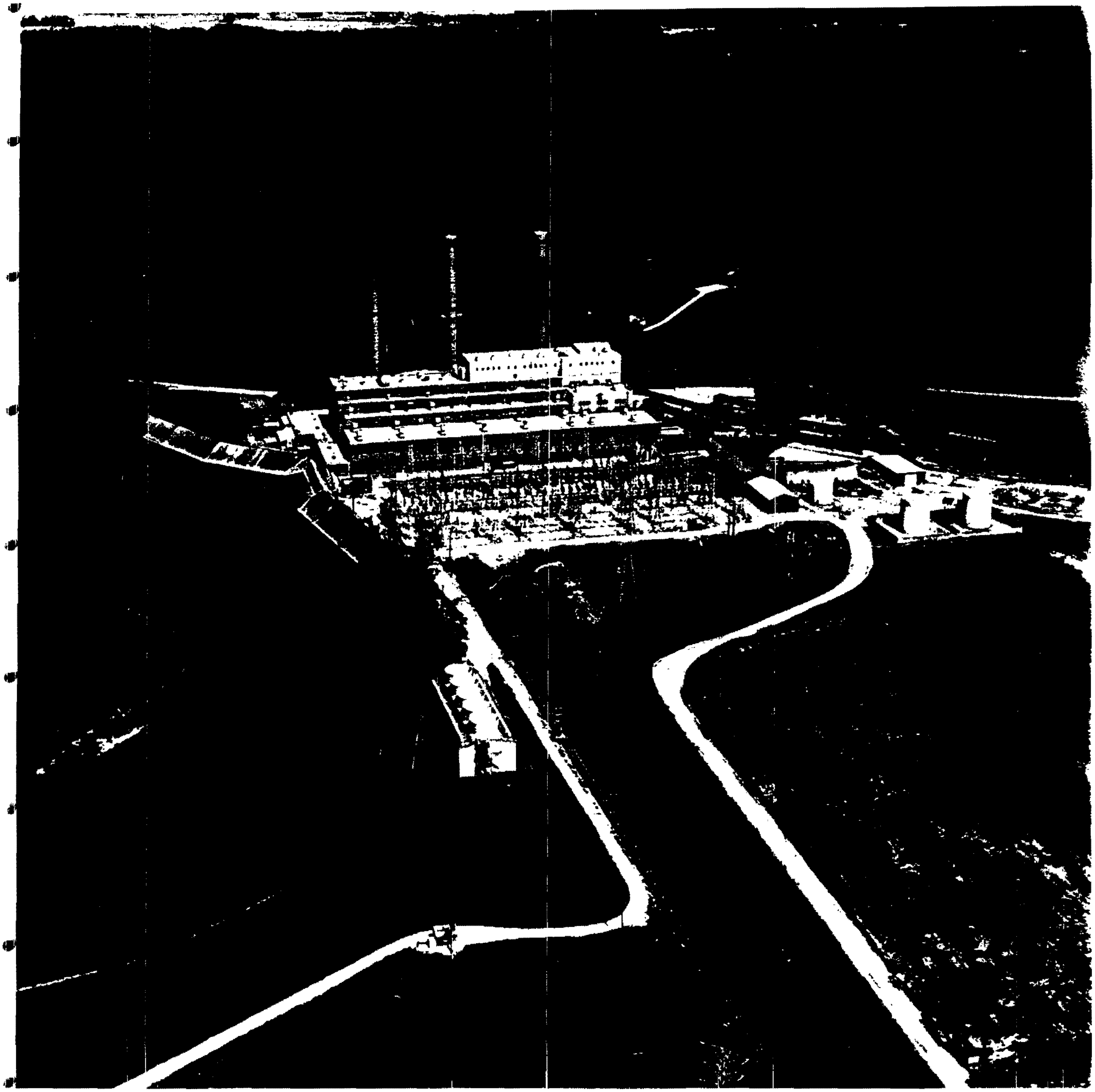


FIGURE 1.2
E.W. STOUT GENERATING STATION

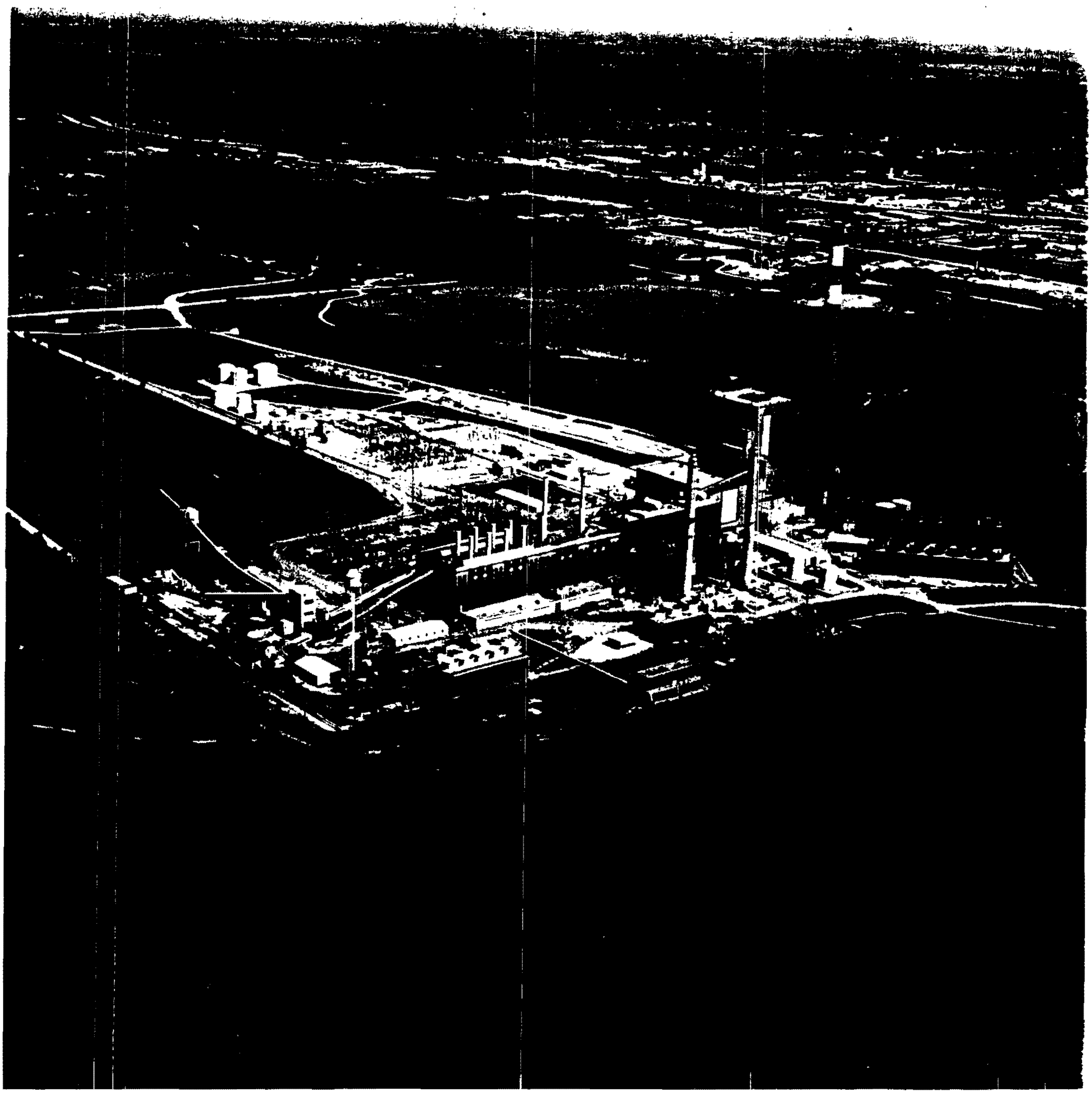
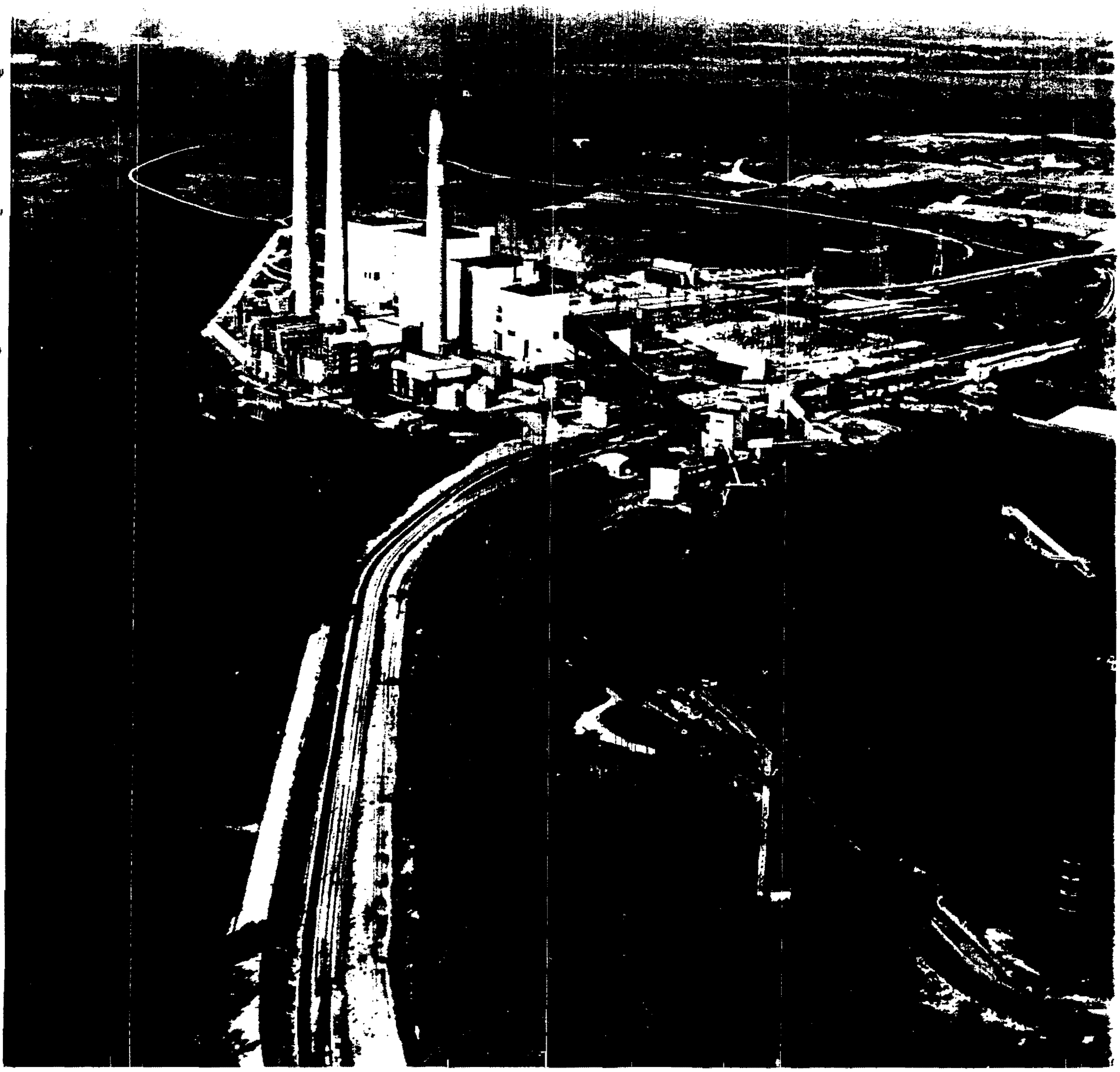


FIGURE 1.3
PETERSBURG GENERATING STATION



1.3 GENERAL APPROACH

The cost estimate was prepared on an item-by-item basis using unit cost factors developed for each cost item from prior dismantling experience or related similar experience. The costs for project management staffing, equipment and consumables, and other collateral costs were estimated on a period-dependent basis (i.e., the magnitude of the expense depends on the duration of the project). Credit for scrap was included to offset the costs of dismantling. Contingency was included to account for unpredictable project events.

The estimates include the costs to dismantle all systems and structures on the sites to 3' below grade, and limited restoration allowing the sites to be released for subsequent alternative re-use. The cost estimates developed reflect demolition by controlled/engineered dismantling rather than a "wrecking ball" approach. Concerns for worker safety reinforces the need for controlled dismantling. Accordingly, all large components were assumed lowered to grade.

The boilers are generally dismantled from the bottom upward, and the boiler steel support structures dismantled from the top downward. The turbine generators, condensate and feedwater systems and the concrete structures will be removed by disassembly and segmentation where necessary.

Limited landscaping includes site contouring and seeding for drainage control. At the end of dismantling activities the plant site will be in a condition such that the land will be available for alternative re-use.

Because of the similarity between several units, a total of eight boilers were characterized in detail, and their inventories applied to other, similarly sized units. The remainder of the site was characterized for each station. The combination of the number of similarly sized boilers times the inventory of the corresponding characterized boiler plus the inventory of the remainder of the site provides a complete estimate of the inventory of each station. Table 1.2 delineates the individual unit type and nominal capacity rating at each station. Also specified is the reference plant used as a basis for determining the boiler inventory for each unit.

TABLE 1.2
STEAM PRODUCTION STATION CAPACITY RATINGS

Station	Unit No.	Type	Nominal Capacity (Mwe)	Reference Plant Used for Boiler Inventory
H.T. Pritchard	1	Oil	44.00	Pritchard Unit 1
(Martinsville, IN)	2	Oil	44.00	Pritchard Unit 1
	3	Coal	44.00	Pritchard Unit 1
	4	Coal	66.00	Pritchard Unit 4
	5	Coal	66.00	Pritchard Unit 4
	6	Coal	100.00	Pritchard Unit 6
TOTAL			364.00 MWe	
E.W. Stout	1	Oil	36.75	Stout Unit 1
(Indianapolis, IN)	2	Oil	36.75	Stout Unit 1
	3	Oil	37.50	Stout Unit 3
	4	Oil	37.50	Stout Unit 3
	5	Coal	100.00	Pritchard Unit 6
	6	Coal	100.00	Pritchard Unit 6
	7	Coal	429.35	Stout Unit 7
TOTAL			777.85 MWe	
Petersburg	1	Coal	220.00	Petersburg Unit 1
(Petersburg, IN)	2	Coal	429.68	Stout Unit 7
	3	Coal	531.52	Petersburg Unit 3
	4	Coal	531.52	Petersburg Unit 3
TOTAL			1712.72 Mwe	

The boilers are top hung units supported by a structural steel building. Furnace design is of the welded waterwall tube type, with oil/coal burners mounted in the front and rear walls. The superheater, reheater and economizer are of the pendant design, supported from the roof structural steel. The air quality control system at each site consists of an electrostatic precipitator to remove fly ash from the boilercombustion gases. In addition to the electrostatic precipitator, the Petersburg Station operates with a flue gas desulfurization (FGD) system on Units 3 and 4 to remove sulfur dioxide from the combustion gases.

1.4 REGULATORY GUIDELINES AND CRITERIA

The White River supplies circulating water for the three generating stations. The U.S. Army Corps of Engineers (ACE) regulations apply to the intake, discharge, lime and coal handling structures at the river. To comply with ACE requirements, the concrete structures should be completely removed, and the river shoreline returned to its natural contour. However, concrete dams and river structures have raised water levels up river by as much as seven feet, while lowering down river water levels by similar amounts. IP&L has determined that removal of the dams could have substantial impacts to the environment. Therefore, at IP&L's direction the study assumes such structures will be left in place and be subject to yearly monitoring to ensure their structural integrity.

All ash disposal sites will be closed by IP&L in accordance with closure plans approved by the State agencies. In accordance with the Indiana Department of Environmental Management (IDEM), closure and post closure plans are required to be updated each year. IP&L has prepared and filed two plans with IDEM: a 10-year plan and a 30-year plan (Ref. 6). The 30-year plan will supersede the 10-year plan, starting in 1994. Accordingly the 30-year plan was used as a basis for developing applicable costs in this dismantling study.

These regulations are a summary of those currently required during the actual dismantling process, the plant would have to meet all applicable State and Federal requirements that exist at that time.

2.0 DISMANTLING OPERATIONS

The cost estimates provided are based on total dismantling of each station after the final unit at each station has been retired. The following sections describe the Project Organization, basic activities and special equipment necessary for accomplishing the dismantling operations.

2.1 PROJECT ORGANIZATION

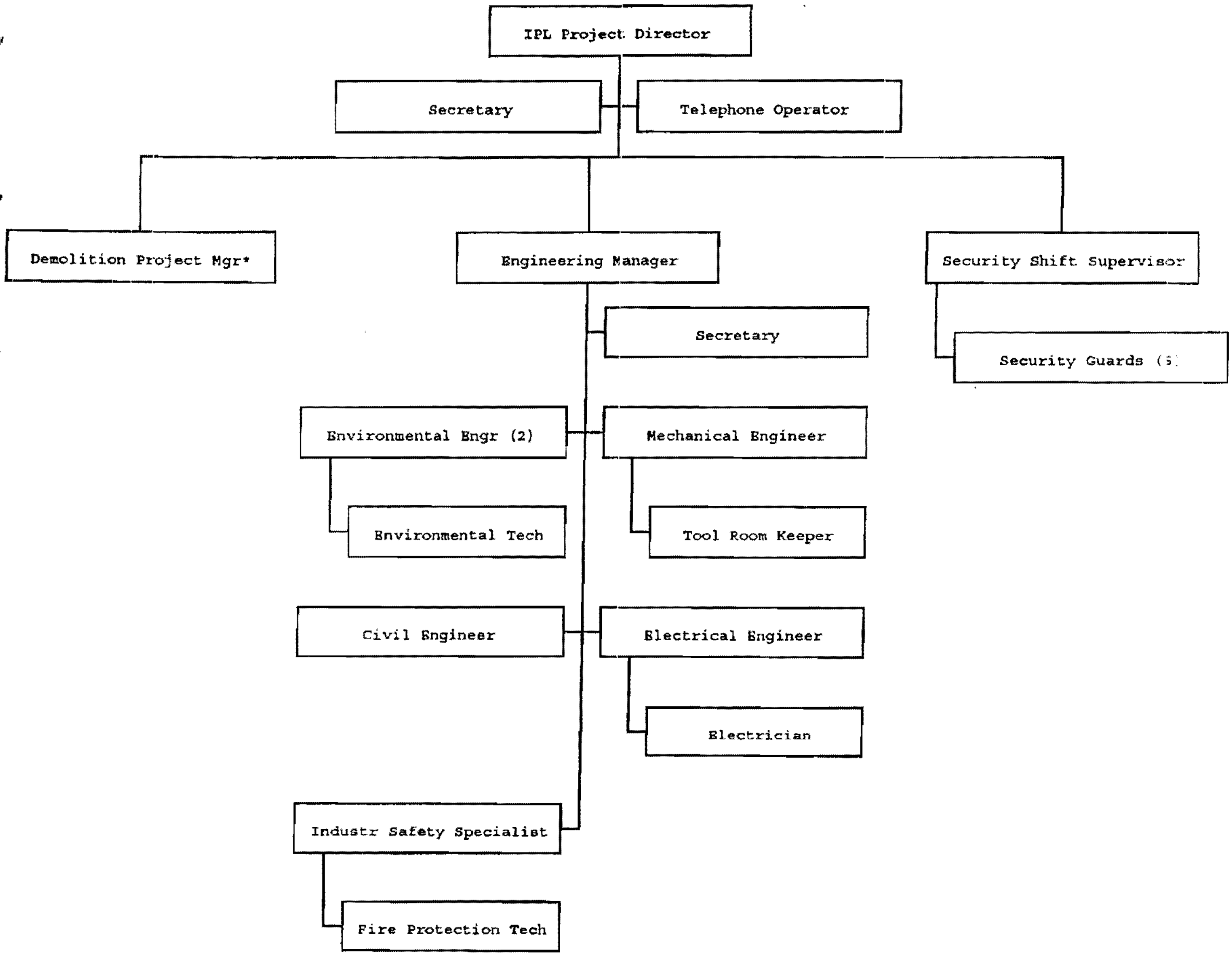
For the purposes of this study each station was assumed to be managed by an IP&L Project Director who will have the authority for dismantling the appropriate station and will direct the project as required. A Demolition Operations Contractor (DOC) who is experienced in dismantling similar facilities will be the prime contractor for the dismantling. The DOC Project Manager will report to the IP&L Project Director. The DOC Project Manager will supervise the day-to-day dismantling of the plant to ensure it is completed in an expeditious and safe manner. The DOC staff will be under the supervision of the DOC Project Manager. Figures 2.1 (a) and (b) outline the project organization.

2.2 DISMANTLING PROGRAM

A dismantling program is characterized by three distinct Periods: Period 1 - Engineering and Planning; Period 2 - Dismantling Operations; and Period 3 - Site Restoration. This section summarizes the activities accomplished under each period of the program. The activities are similar for each site.

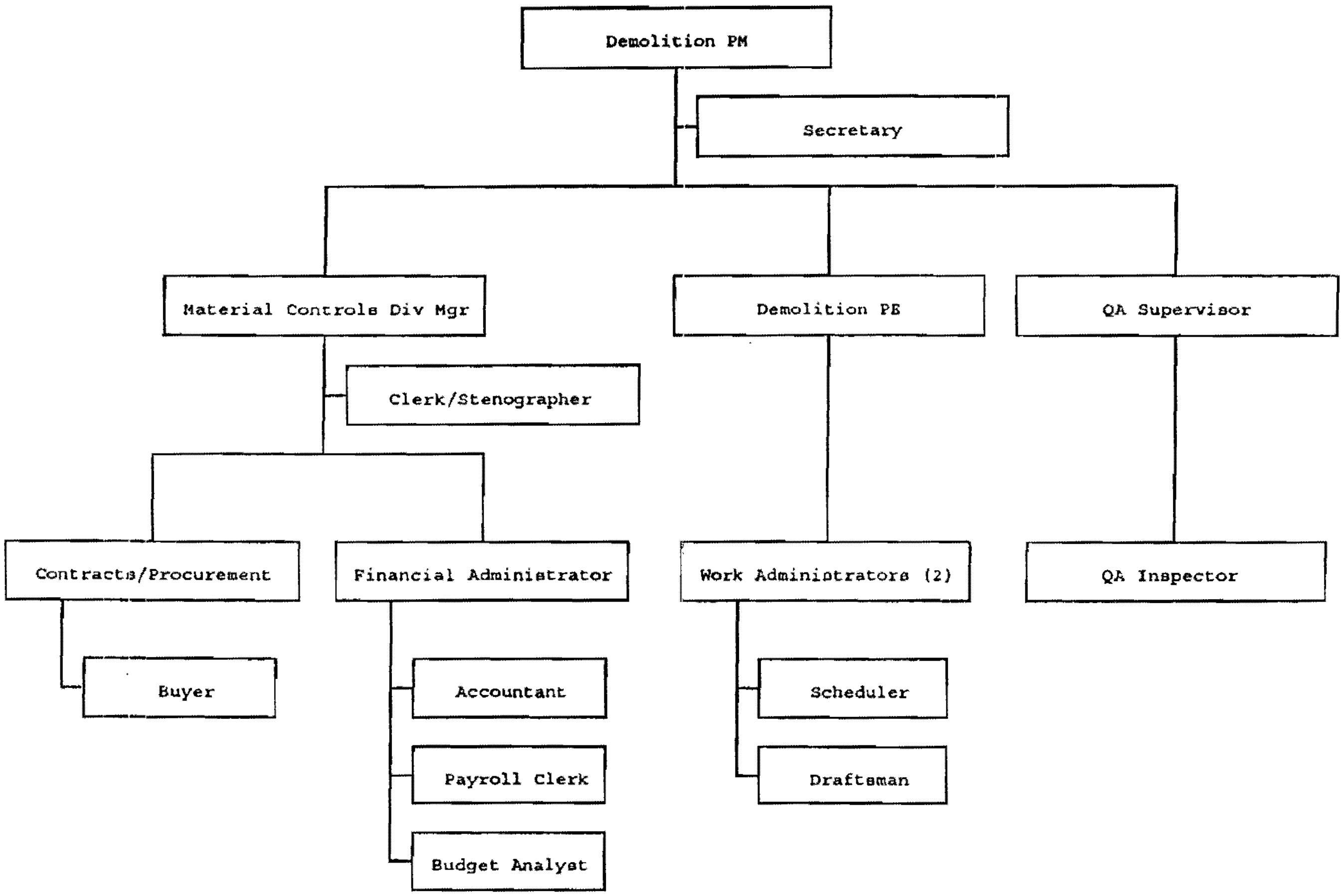
Although detailed procedures for each activity required are not provided, and actual sequences of work may differ from that presented herein, these activity descriptions provide a basis for the detailed engineering, planning and scheduling at the time of dismantling.

FIGURE 2.1 (a)
DISMANTLING PROJECT ORGANIZATION
UTILITY STAFF



* Refer to Figure 2.1 (b)

FIGURE 2.1 (b)
DISMANTLING PROJECT ORGANIZATION
DOC STAFF



2.2.1 Period 1 - Engineering and Planning

Preliminary Planning/Preparation:

A preliminary planning phase of the program begins once IP&L has determined that a station has reached the end of its useful life and should be dismantled. During this phase, IP&L assembles the IP&L dismantling management organization and accomplishes those site preparation activities necessary to provide a smooth transition from plant operations to site dismantling. Costs incurred during this preliminary phase of the program are included in the dismantling costs presented in this study.

IP&L prepares the stations for dismantling by performing the following activities:

1. Remove temporary buildings and personal property;
2. Incinerate (within boiler) any coal in active or inactive storage areas;
3. Burn any remaining fuel oil in storage tanks;
4. Install environmental monitoring equipment;
5. Obtain appropriate permits for disposal of hazardous and toxic materials;
6. Empty coal silos;
7. Dewater ash ponds;
8. Drain acid and caustic tanks;
9. Empty all electrostatic precipitators and fly ash silos of fly ash;
10. Empty limestone stockpiles/reserves;
11. Empty the FGD system of all fly ash/limestone;

12. Return all nitrogen and other gas storage cylinders to suppliers;

13. Drain and dry all water retention lagoons;

14. Drain slurry thickeners and remove and dispose of slurry; and

15. Select Demolition Operations Contractor (DOC).

Once IP&L has selected the DOC, the detailed engineering and planning can begin.

Detailed Engineering and Planning:

Detailed Engineering and Planning activities begin once IP&L has selected a DOC to manage and direct the dismantling program. Such activities include preparation of activity specifications which identify the major work activities to be performed, and how to accomplish them. Detailed work procedures which provide the step-by-step instructions for the work crews are also prepared during this period.

The DOC proceeds with dismantling engineering and planning by performing the following activities:

1. Review plant drawings and specifications;

2. Perform detailed plant system material inventory;

3. Prepare description of final site configuration;

4. Identify major work sequence;

5. Prepare dismantling activity specifications and work orders/forms;

6. Prepare detailed dismantling procedures;

7. Perform safety analysis of dismantling activities;

8. Perform safety analysis on fluids in plant systems and the effects of cutting upon these fluids;

9. Prepare and submit dismantling plan to the utility for review and approval;

10. Submit application for plant demolition permit from appropriate authorities; and

11. Receive dismantling authorization from IP&L.

2.2.2 Period 2 - Dismantling Operations

Mobilize the DOC staff; provide temporary services/facilities to support dismantling operations; subcontract/procure equipment, rigging, special equipment and tools; and mobilize the labor force. The DOC initiates dismantling and performs the following activities:

1. Excavate and collapse circulating water lines and backfill voids;

2. Remove coal yard equipment, railcar unloading structures, conveyors, transfer towers and breaker house;

3. Remove nonessential Systems A (Appendix A) equipment including main steam piping, generator auxiliary equipment, feed water heaters and pumps, various water systems, main condenser, condensate;

4. Remove intake and discharge structures;

5. Remove nonessential Systems B (Appendix A) equipment that must be removed prior to start of boiler structure removal, including fly-ash handling, coal handling, burner fuel supply, etc.;

6. Remove FGD system by cutting scrubber tanks and remove structure;

7. Remove electrostatic precipitator by cutting collection electrodes and casing;

8. Remove top of boiler enclosure to allow access to platens;

9. Remove Boiler:

   a) Place steel beam across top of boiler steel structure and attach hoist to beam. Rig platens to hoist and lower them to grade to be cut.

   b) Remove boiler waterwall from the bottom of the furnace to the top, using a hoist attached to building steel to lower waterwall sections to grade for removal.

   c) Remove upper and lower headers by rigging them to steel beam across top of boiler steel structure and lowering them to grade to be cut and removed.

10. Remove deaerator by cutting shell in place and lowering pieces to grade for removal.

11. Disassemble turbine/generator for delivery to a scrap yard;

12. Remove all essential Systems C (Appendix B) such as fire protection, compressed air, electrical;

13. In conjunction with removal of essential systems, remove boiler structural steel from top to bottom, placing small pieces in a transfer container and large pieces rigged to the crane and lowered to grade for removal;

14. Remove the turbine building shell and floor;

15. Remove remaining site buildings;

16. Blast and remove to grade level the turbine-generator pedestal monolithic concrete;

17. Remove the FGD/electrostatic precipitator foundations;

18. After all site buildings have been removed, control blast the chimney stacks to grade and remove the concrete and steel rubble; (Note: Stout Units 1-4 roof-mounted stacks will be removed and lowered to the ground for disposal as scrap.)

19. Dismantle the cooling towers to 3 feet below grade, breaking large concrete pieces into rubble to be used for fill;

20. Control blast the stack, turbine and boiler foundations (sufficient to allow for ground water penetration);

21. Remove all rail spurs.

2.2.3 Period 3 - Site Restoration

Following completion of the dismantling operations, site restoration activities are initiated. The de-watered ash ponds and coal storage areas, the limestone stackout areas and the SO_2 scrubber sludge disposal areas are to be covered with 24 inches of clay and 6 inches of topsoil. No attempt shall be made to restore the original contour of the land. Landscaping will be limited to grading and seeding necessary for site drainage and erosion control. A final dismantling report is issued upon completion of the program. All personnel and equipment are demobilized from site. The 30-year, post-closure monitoring program (Ref. 6) is implemented.

2.3 SPECIAL EQUIPMENT

A track-mounted cutting torch will be used to segment the waterwall headers. The track is magnetically attached to the item to be cut, and the cutting torch is advanced along the track to make the cut. This technique allows greater output than manual cutting for extremely thick sections.

A front-end loader with a demolition bucket is also used during the dismantling operations. The bucket has two movable jaws which allow it to pick up scrap and place it on a truck for removal. Other equipment used in the dismantling process, including forklifts, cutting torches, wheeled backhoes and mobile cranes, are readily available from rental equipment yards.

To the extent possible, existing plant equipment, such as the turbine crane, will be used during the demolition activities.

3.0 COST ESTIMATE

Site-specific cost estimates were prepared for the dismantling of the H.T. Pritchard, E.W. Stout and Petersburg Generating Stations. The basis, methodology, assumptions and total estimated costs are described in the following sections.

3.1 BASIS OF ESTIMATE

Site-specific cost estimates were developed using drawings and the inventory documents provided by IP&L. These drawings and documents were used to determine the general arrangement of the facility and to develop estimates of building concrete volumes, steel quantities and component inventories for the various stations.

The cost estimates are based on averages, such that the total costs shown for the projects are a reasonable approximation of what is expected to occur. Individual cost elements will likely vary from the estimated values. Accordingly, this estimate is not a substitute for the detailed engineering and planning that is performed in preparation for the dismantling of the units.

Listed below are the major factors considered as the basis of the cost estimates:

1. Component and structural inventories were developed from information provided by IP&L.

2. Employee salary and craft labor rates for site administration, operations, construction and maintenance personnel were provided by IP&L for positions identified by TLG.

3. Engineering services for such items as activity specifications, detailed procedures, structural analysis and modifications, etc. will be provided by the DOC.

4. Material and equipment costs for conventional demolition and/or construction activities are taken from R.S. Means Construction Cost Data (Ref. 1).

5. Costs in this estimate are in 1993 dollars.

6. Site insurance costs were provided by IP&L.

7. Closure and post-closure costs for the solid waste disposal facilities and wastewater treatment facilities were provided by IP&L (Ref. 6).

3.2 METHODOLOGY

The methodology used to develop the cost estimates follows the basic approach presented in the AIF/NESP-036 (Ref. 2) and the US DOE "Decommissioning Handbook" (Ref. 3). These references utilize a unit cost factor method for estimating decommissioning activity costs to simplify the estimating calculations. Unit cost factors for concrete removal ($/cubic yard) steel removal ($/ton) and cutting costs ($/in) were developed from the labor cost information provided by IP&L. With the item quantity (cubic yards, tons, inches, etc.) developed from plant drawings and inventory documents, the activity-dependent costs are estimated. The unit cost factors used in this study reflect the latest available information about worker productivity in dismantling programs.

The activity duration critical path was used to determine the total dismantling program schedule. The program schedule is used to determine the period-dependent costs for program management, administration, field engineering, equipment rental, quality assurance and security. IP&L provided typical salary and hourly rates for personnel associated with period-dependent costs. The costs for conventional demolition of structures, materials, backfill, landscaping and equipment rental were obtained from the "Building Construction Cost Data" published by R.S. Means (Ref. 1). Examples of unit cost factor development are presented in the AIF "Guidelines" study (Ref. 2). A sample development of a unit cost factor is reproduced in Appendix C. Appendix D lists specific factors developed for the analyses. The bases for developing the unit cost factors are summarized in Appendix E.

The unit cost factor method provides a demonstrable basis for establishing reliable cost estimates. The detail of activities for labor costs (by craft), equipment and consumables costs provide assurance that cost elements have not been omitted. These detailed unit cost factors coupled with the site-specific inventory of piping, components and structures provide a high degree of confidence in the cost estimates.

The activity- and period-dependent costs are combined to develop the total decommissioning costs. A contingency is then applied. "Contingencies" are defined in the American Association of Cost Engineers' Cost Engineers' Notebook (Ref. 4) as "specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur." The cost elements in this estimate are based upon ideal conditions: therefore, a contingency factor has been applied. Examples of items which could occur that have not otherwise been accounted for in this estimate include: the effects of craft labor strikes; bad weather halting or slowing down operations; equipment/tool breakage; and changes in the anticipated plant shutdown conditions, etc. In the AIF/NESP-036 study, (Ref. 2), the types of unforeseeable events that are likely to occur are discussed and guidelines are provided for percentage contingency in each category. Application of contingency is assigned on a line-item basis for this estimate. The following contingency values were used in developing this estimate and were selected based on TLG's engineering and field dismantling experience:

* Component Removal; Structure Demolition Material Handling & Shipping; Staffing/ Labor Costs; Tools & Equipment; Landscaping - 15%
* Insurance - 10%
* Asbestos Removal - 25%

3.3 ASSUMPTIONS

The following are the major assumptions for developing the dismantling estimates.

1. Asbestos and transite materials will be disposed of at licensed facilities. Materials scheduled for removal under existing abatement programs are excluded from the study.

2. All transformers have PCB-free oil. Lubricating and transformer oils are drained and removed from site by a waste disposal vendor.

3. Environmental regulations in effect in 1993 shall be in force during the dismantling effort.

4. Only buildings and property listed in the study are included in the dismantling costs. (e.g., the gas turbines scheduled for installation at Stout Units 4 and 5 are not included in this study.)

5. All railroad spurs within the perimeter fence shall remain in place during dismantling and removed prior to completion of the project.

6. All coal and oil that can be economically reclaimed will be transferred to another site.

7. Coal silos and fuel oil tanks will be empty prior to the start of dismantling.

8. Precipitators, FGD system and ash silos will be empty of fly ash prior to the start of dismantling.

9. Acid, caustic and demineralizer tanks will be empty prior to the start of dismantling.

10. The demolition will be performed by a DOC who will provide adequate staff and equipment to complete the dismantling.

11. Overhead and profit by the DOC will be 62.6% on labor, 15% on equipment.

12. Electrical power will be provided by the DOC using local power.

13. Office trailers will be used by IP&L and DOC personnel.

14. Essential systems listed under Appendix B will remain in service until the latest possible time.

15. The chimney stacks will be control blasted to the ground and broken into rubble, the steel liners cut and removed, and the foundations control blasted to break the concrete in place so that groundwater drainage is provided.

16. The cooling towers will be demolished and removed as mechanical buildings, the concrete basin reduced to rubble and the resulting voids backfilled.

17. Coal handling facilities will be completely removed and the voids backfilled.

18. The concrete turbine-generator pedestals will be removed to 3 feet below grade elevation.

19. The turbine and boiler building foundations will be control blasted to break concrete in place to provide ground water drainage.

20. Underground piping, except for circulating water piping, will be capped and abandoned in place.

21. Concrete circulating water piping (≤20 ft deep) will be excavated, collapsed and the resulting void filled. Concrete piping more than 20 ft deep will be capped and abandoned in place.

22. Certain structures with below-grade concrete will have concrete removed to 3 feet below grade, with any resulting voids filled to grade.

23. The intake and discharge structure concrete will be completely removed.

24. Water drainage holes will be drilled in the bottom of all structures abandoned below grade.

25. All systems will be evaluated by engineering prior to dismantling to determine if cleaning or flushing is required prior to removal.

26. Switchyard dismantling is not included in this study.

27. Boundary fence, roads and parking lots shall remain in place after dismantling.

28. Valves 2" and smaller will be removed with piping. Valves larger than 2" are removed individually.

29. Fire hose racks will be removed with piping.

30. Nitrogen storage cylinders and other gas storage containers shall be removed from the site prior to dismantling.

31. All clean rubble generated during dismantling activities will be used to fill voids.

32. All scrap equipment and material will be placed in the laydown area for removal by a scrap dealer. All equipment is assumed to have no salvage value other than scrap value.

33. FGD landfill areas will have been shutdown by IP&L and made ready for closing prior to start of dismantling activities.

34. Fly ash ponds closure costs are included as part of this dismantling estimate.

35. The boiler platens will be cut from their boiler supports, lowered to the ground and sectioned into 8' x 8' pieces at a cutting area.

36. Conveyors will be rigged to cranes, cut, lowered to the ground and cut into 10-foot sections.

37. Contingency will be applied to project costs on a line-item basis.

38. Overhead rate on utility staff will be 51.75%.

39. All existing dams will be left in place.

40. Security will be provided by the DOC.

41. All non-asbestos waterwall and duct insulation will be removed for disposal at a local sanitary landfill.

42. The dismantling process shall be by an engineered process rather than by wrecking ball demolition.

3.4 COST ESTIMATE SUMMARY

Tables 3.1, 3.2 and 3.3 provide a summary of the expenditures for the dismantling of the H.T. Pritchard, E.W. Stout and Petersburg Stations, respectively. The tables present a breakdown of the dismantling costs by Plant Type. Detailed cost tables listing costs for the major dismantling activities by individual plant for each station may be found in Appendices F, G and H. All costs are in constant 1993 dollars.

TABLE 3.1

H.T. PRITCHARD STATION
COST SUMMARY BY PLANT TYPE*

Plant Type	Plant Dismantling Cost	Period-Dependent Cost	Scrap	Total
Steam Plant	$24,706	$12,222	($10,868)	$26,059
Diesel-Generators	$ 5	$ 3	($ 4)	$ 4
Total	**$24,711**	**$12,224**	**($10,872)**	**$ 26,063**

* Notes:
- Parentheses indicate a credit
- Columns may not total due to rounding
- Thousands of 1993 Dollars

TABLE 3.2

E.W. STOUT STATION
COST SUMMARY BY PLANT TYPE*

Plant Type	Plant Dismantling Cost	Period-Dependent Cost	Scrap	Total
Steam Plant	$73,128	$12,380	($17,459)	$32,523
Combustion Turbines	$ 10	$ 3	($ 8)	$ 6
Diesel-Generators	$ 10	$ 3	($ 8)	$ 6
Total	**$37,622**	**$12,386**	**($17,474)**	**$32,534**

* Notes:
- Parentheses indicate a credit
- Columns may not total due to rounding
- Thousands of 1993 Dollars

TABLE 3.3

PETERSBURG STATION
COST SUMMARY BY PLANT TYPE*

Plant Type	Plant Dismantling Cost	Period-Dependent Cost	Scrap	Total
Steam Plant	$57,980	$25,440	($19,822)	$63,597
Diesel-Generators	$ 15	$ 7	($ 12)	$ 10
Total	**$57,995**	**$25,447**	**($19,834)**	**$63,608**

* Notes:
- Parentheses indicate a credit
- Columns may not total due to rounding
- Thousands of 1993 Dollars

4.0 SCHEDULE ESTIMATE

Using information presented in AIF/NESP-036 (Ref. 2) and recent industry experience, dismantling project schedules have been developed for the H.T. Pritchard, E.W. Stout and Petersburg Generating Stations. The assumptions supporting the schedules are discussed in Section 4.1. Figures 4.1, 4.2 and 4.3 present the project schedules for key activities for the dismantling of the Pritchard, Stout and Petersburg Stations, respectively. Activities listed in the schedules do not reflect a one-to-one correspondence with the activities listed in the cost tables in Appendices F, G and H. Some activities have been divided for clarity, while others have been combined for convenience. The schedules were prepared using the "Harvard Project Manager" computer software (Ref. 5).

4.1 SCHEDULE ESTIMATE ASSUMPTIONS

The schedules reflect the results of a precedence network developed for the dismantling activities, i.e., a PERT (Programmed Evaluation and Review Technique). The durations used in the precedence network reflect the actual manhour estimates from the detailed cost tables in Appendices F, G, and H. The schedule outputs were adjusted by stretching certain activities over their slack range and by "pushing" other activities to the end of their slack period.

Both the project schedules and the manpower estimates account for the limitations of personnel workspace and maximum worker safety and protection. Such considerations can contribute to an increase in project schedules.

The following limitations and assumptions are reflected in the development of the dismantling schedules.

1. All work is performed during an 8-hour workday, 5 days per week with no overtime. There are eleven paid holidays per year.

2. Multiple crews work parallel activities to the maximum extent possible, consistent with optimum efficiency, adequate access for cutting, removal and laydown space, and with the stringent safety measures necessary during demolition of heavy components and structures.

3. Boiler Removal

It is assumed that only two crews, working on opposite sides of the boiler, can safely work on waterwall removal at one time. Since the work is in a confined and hazardous area, additional crews would increase the probability of tools, waterwall panels or materials dropping from above.

4. Boiler Steel Structure

The boiler steel structures are adjacent to and at a higher elevation than the turbine buildings. To expedite the schedule it would be desirable to proceed with dismantling of both the boiler steel structures and the turbine buildings in parallel. To further expedite the process, the past practice in dismantling structural steel and/or large components was to simply torch-cut and drop sections to lower elevations for removal and handling. However, in the interest of safety, demolition of these structures is scheduled in series rather than in parallel, using a controlled "cut and lower" technique.

5. Chimney Stack

Demolition of these structures is by controlled blasting. Blast fragments have the potential to cause injury to personnel and ground vibrations could collapse other structures or trailers. In order to limit risk of injury or damage, demolition of these structures has been delayed until the number of on-site personnel and structures has been reduced.

6. For plant systems removal, the systems with the longest removal durations in areas on the critical path are considered to determine the duration of the activity.

4.2 PROJECT SCHEDULE

The period-dependent costs presented in the cost tables in Appendices F, G and H are based upon the durations developed in the schedules for the respective station dismantlings. Durations were established between several milestones in each project period; these durations were used to establish a critical path for the entire project. In turn, the critical path durations for each period were used as the basis for determining the total costs for these items. Figures 4.1, 4.2 and 4.3 present the dismantling schedules for the Pritchard, Stout and

Petersburg stations, respectively. Appendix I contains a description of various tasks listed in these figures.

Project timelines for the dismantling of the Pritchard, Stout and Petersburg Stations are included in Figures 4.4, 4.5 and 4.6, respectively.

FIGURE 4.1
DISMANTLING ACTIVITY SCHEDULE FOR H.T. PRITCHARD

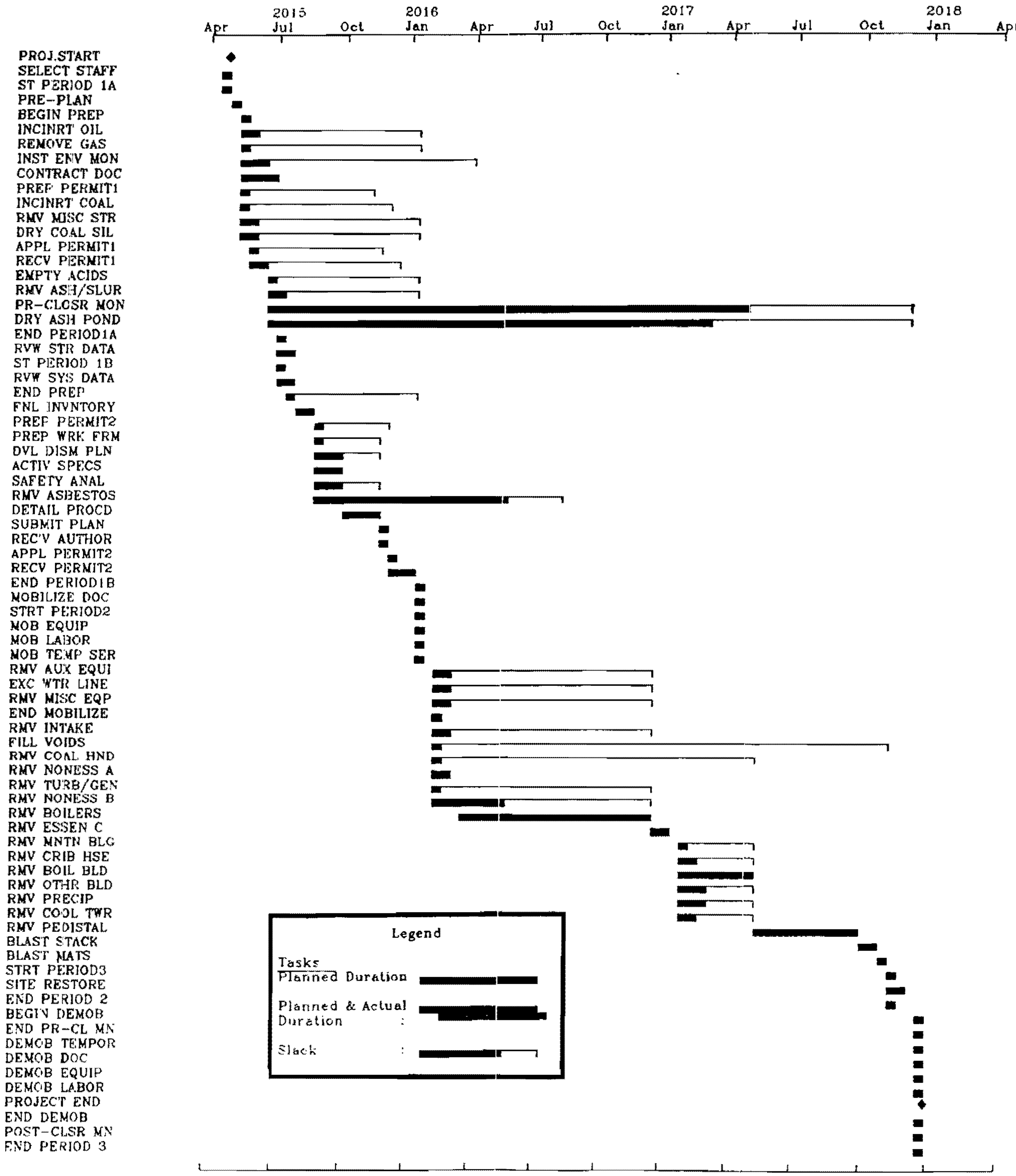


FIGURE 4.2
DISMANTLING ACTIVITY SCHEDULE FOR E.W. STOUT

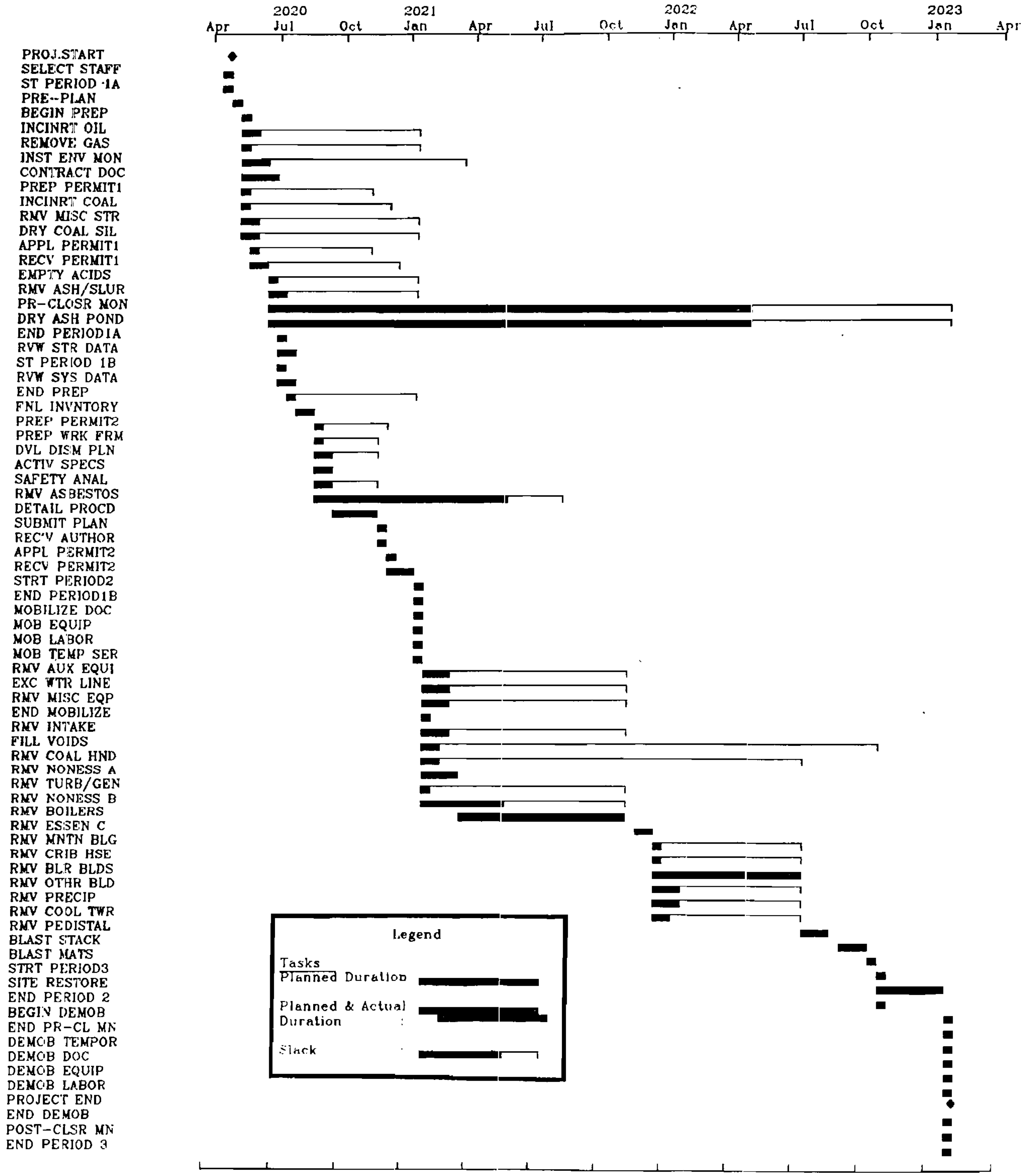


FIGURE 4.3
DISMANTLING ACTIVITY SCHEDULE FOR PETERSBURG

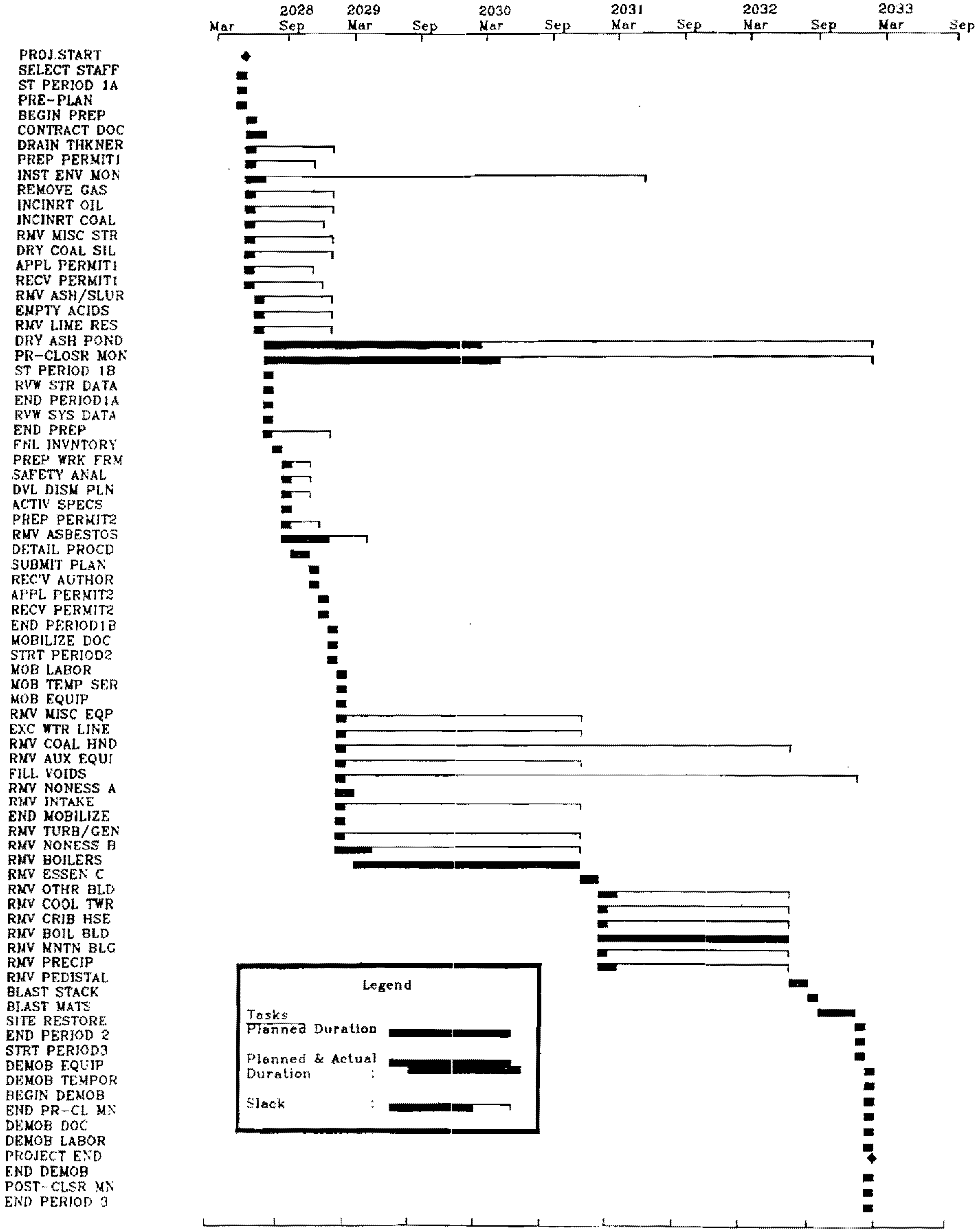


FIGURE 4.4

DISMANTLING TIMELINE FOR H.T. PRITCHARD
(not to scale)

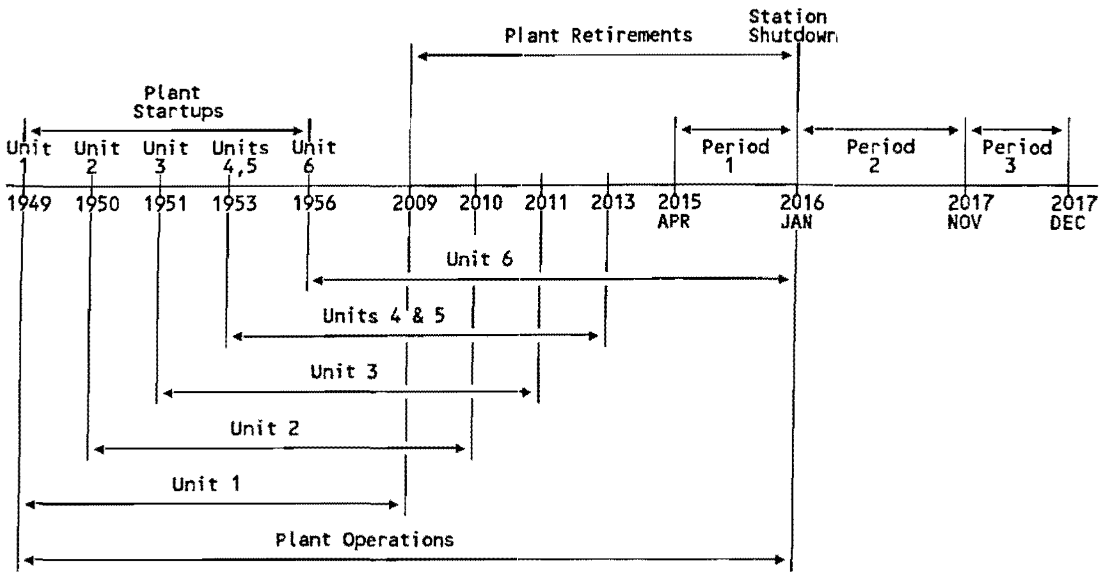


FIGURE 4.5

DISMANTLING TIMELINE FOR E.W. STOUT
(not to scale)

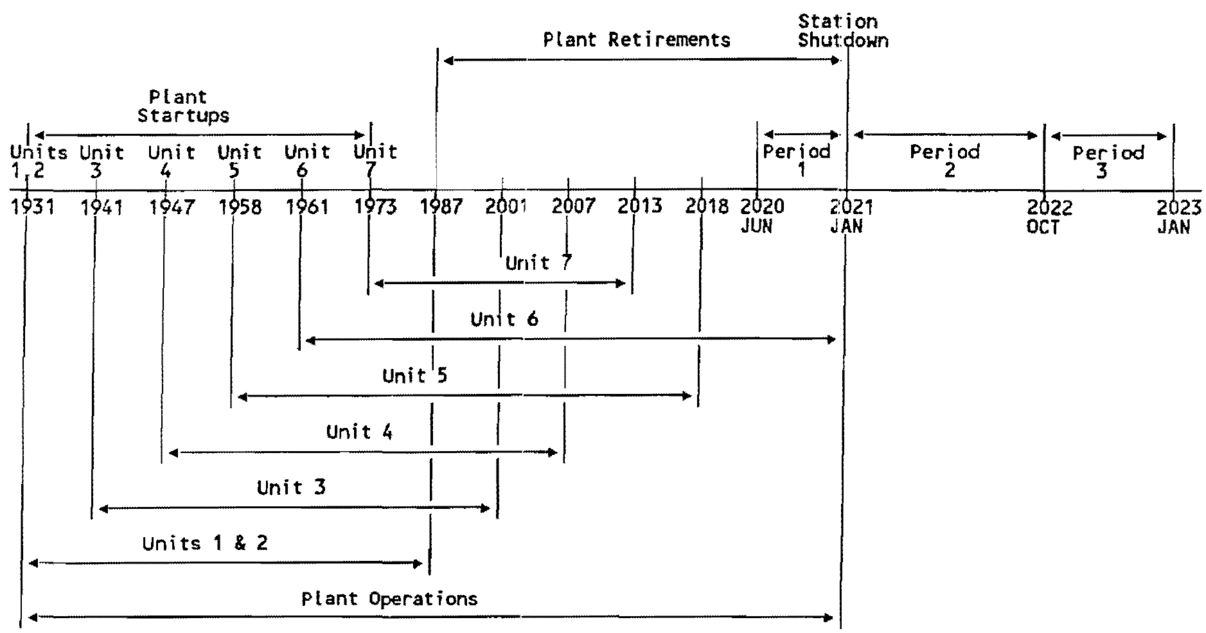
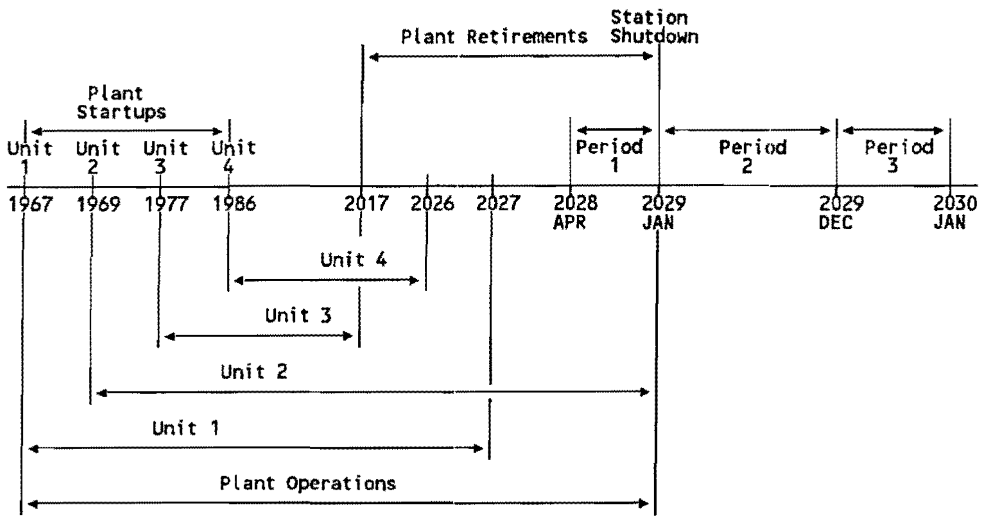


FIGURE 4.6

DISMANTLING TIMELINE FOR PETERSBURG
(not to scale)



5.0 WASTE MANAGEMENT

There are several types of hazardous and non-hazardous wastes located on the plant sites. These include asbestos insulation, calcium silicate insulation, fuel oil and non-PCB equipment oil.

Asbestos insulation will be collected and removed to a licensed landfill for disposal. If additional hazardous wastes are discovered during dismantling operations or if environmental regulations change, then appropriate measures will be taken by IP&L or the DOC. Fuel oil in the fuel system of the plant should be burned off in the boiler. Any residual fuel oil and any oil obtained from equipment draining will be collected and removed by a waste hauler for disposal.

The non-hazardous wastes will be disposed of in a safe and reasonable manner. Calcium silicate insulation will be buried in the voids of the plant, as it is of mineral composition similar to sand and should not present an environmental hazard.

6.0 SCRAP VALUE

Dismantling is assumed to take place sufficiently far in the future such that all equipment will be worn, obsolete and suitable for scrap only. No equipment is salvageable as used equipment.

The value of scrap was estimated from current market value in the Indianapolis area. In general, scrap materials were assumed removed from their installed location and placed on a loading dock or laydown area on site for a scrap dealer to remove. The value of the scrap was estimated using a local market value of $100 per ton for carbon steel, $1100 per ton for copper and $240 per ton for stainless steel. The estimated scrap amounts for each station are summarized in Table 6.1 below:

TABLE 6.1

ESTIMATED SCRAP QUANTITIES

Station	Carbon Steel (tons)	Copper (tons)	Stainless Steel (tons)
H.T. Pritchard	40,743	5,800	1,741
E.W. Stout	73,228	8,730	2,285
Petersburg	108,738	7,761	1,764

7.0 RESULTS

Dismantling technology is well established. The techniques, tools and equipment necessary to dismantle the H.T. Pritchard, E.W. Stout and Petersburg Generating Stations are available and have been demonstrated.

The cost estimates developed reflect demolition by controlled/engineered dismantling rather than a "wrecking ball" approach. While the "cut and drop" approach may have been the accepted practice for older, bottom-supported boilers, it is not acceptable for top-supported boilers 200 feet or more in height. Concerns for worker safety reinforces the need for controlled dismantling. Accordingly, all large components and major steel structures were assumed lowered to grade. The estimated costs considered necessary to safely dismantle the stations are summarized in Tables 7.1, 7.2 and 7.3.

The dismantling and utility staffs along with the removal activity combine to represent the majority of the cost to dismantle the stations. This is a direct result of the labor-intensive nature of the dismantling process.

This study provides an estimate for dismantling under current requirements based on present-day costs and available technology. As additional dismantling experience becomes available, cost estimates should be modified to reflect this experience.

TABLE 7.1

SUMMARY OF H.T. PRITCHARD STATION DISMANTLING COSTS*

Activity	Costs	Percent
Asbestos Abatement	$ 3,934	10.65%
Systems Removal	$ 9,652	26.13%
Structures Demolition	$ 7,122	19.28%
Landscaping	$ 3,178	8.60%
Utility Staffing	$ 4,197	11.36%
DOC Staffing	$ 4,232	11.46%
Liability Insurance	$ 276	0.75%
Tools & Equipment	$ 4,344	11.76%
Total Dismantling Costs	**$36,935**	**100.00%**
Scrap Credit	($10,872)	
Total Project Cost	**$26,063**	

* Notes:
- Parentheses indicate a credit
- Columns may not total due to rounding
- Thousands of 1993 Dollars

TABLE 7.2

SUMMARY OF E.W. STOUT STATION DISMANTLING COSTS*

Activity	Costs	Percent
Asbestos Abatement	$ 3,740	7.48%
Systems Removal	$13,885	27.76%
Structures Demolition	$12,058	24.11%
Landscaping	$ 7,041	14.08%
Utility Staffing	$ 4,155	8.31%
DOC Staffing	$ 4,238	8.47%
Liability Insurance	$ 485	0.97%
Tools & Equipment	$ 4,407	8.81%
Total Dismantling Costs	**$50,008**	**100.00%**
Scrap Credit	($17,474)	
Total Project Cost	**$32,534**	

* Notes:
- Parentheses indicate a credit
- Columns may not total due to rounding
- Thousands of 1993 Dollars

TABLE 7.3

SUMMARY OF PETERSBURG STATION DISMANTLING COSTS*

Activity	Costs	Percent
Asbestos Abatement	$3,164	3.79%
Systems Removal	$20,044	24.02%
Structures Demolition	$21,797	26.12%
Landscaping	$11,978	14.36%
Utility Staffing	$ 7,744	9.28%
DOC Staffing	$ 8,006	9.59%
Liability Insurance	$ 2,117	2.54%
Tools & Equipment	$ 8,592	10.30%
Total Dismantling Costs	**$83,442**	**100.00%**
Scrap Credit	($19,834)	
Total Project Cost	**$63,608**	

* Notes:
- Parentheses indicate a credit
- Columns may not total due to rounding
- Thousands of 1993 Dollars

8.0 REFERENCES

1. "Building Construction Cost Data, 1993," Robert Snow Means Company, Inc., Duxbury MA.

2. T.S. LaGuardia, et al, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates", AIF/NESP-036, May 1986.

3. W.J. Manion and T.S. LaGuardia, "Decommissioning Handbook," U.S. Department of Energy, DOE/EV/10128-1, November 1980.

4. Cost Engineers Notebook: American Association of Cost Engineers, AA-4.000,

   p. 3 of 22, Rev. 2 (January 1978) (Updated periodically).

5. "Harvard Project Manager", Version 3.01, Software Publishing Corporation, 1988.

6. "Estimated Closure Costs for the IP&L Landfill and Ash Ponds to Decommission Plants", R. James Meiers, Environmental Affairs Department; Indianapolis Power & Light Company; transmitted to R.J. Guerra, TLG Engineering, Inc., May 5, 1993.

APPENDIX A

LISTING OF NON-ESSENTIAL SYSTEMS

APPENDIX A

LISTING OF NON-ESSENTIAL SYSTEMS

The non-essential systems are divided into two groups: Systems A and Systems B. Systems in the Systems A classification must be removed before initiating boiler removal while those in the Systems B classification can be removed anytime prior to boiler structure removal. Plant systems are divided into Systems A and Systems B in this table to correlate with the project schedule.

Systems A

* Main Steam, Hot and Cold Reheat
* Extraction Steam
* Boiler Feedwater
* Condensate
* Auxiliary Steam
* Circulating Water
* Equipment Cooling Water
* Service Water
* Seal Water
* Condensor Air Removal
* Lubricating Oil
* Hydrogen and Carbon Dioxide
* Acid, Caustic and Boiler Chemical Feed
* Sampling and Analysis
* Soot Blowing

Systems B

* Coal Handling/Supply
* Fuel Oil Supply
* Fly-Ash Handling/Storage
* Vents
* Drains
* Combustion Air and Flue Gas
* Waste Treatment
* Turbine-Generator
* Diesel/Gas-Generator

APPENDIX B

LISTING OF ESSENTIAL SYSTEMS

APPENDIX B

LISTING OF ESSENTIAL SYSTEMS

The essential systems are those that are to remain operational during dismantling activities. They will be removed at the latest possible time. The systems listed herein are designated as Systems C on the project schedule.

1. Compressed Air

   This system will be used to supply air to power various small tools used during the dismantling process.

2. Fire Protection

   The pressurized water fire protection system will remain operational to provide fire suppression services. A fire could be started from cutting torch slag or from an electrical source. A means of fire protection is normally required by insurance companies on industrial properties. After the pressurized water system is removed, portable chemical fire extinguishers will be used throughout the site.

3. Building Heating

   The heating system for the service building and control room will be operational until the buildings are dismantled. Should dismantling occur during the winter months, the turbine building heating system will remain operational as long as is necessary.

4. Electrical

   The control room equipment is required to provide monitoring of fire protection and electrical systems until they are removed. The switchgear and electrical conduit provide electrical power to the other essential systems and temporary lighting required by craftsmen to perform removal activities.

5. Other Miscellaneous Plant Equipment

   All equipment not covered in previously listed systems.

APPENDIX C

UNIT COST FACTOR DEVELOPMENT

APPENDIX C

UNIT COST FACTOR DEVELOPMENT

Example: Unit Cost Factor For Removal of Heavily Reinforced Concrete With #9 Rebar

1. SCOPE

Heavily reinforced concrete and other structures of comparable thickness and accessibility will be removed using controlled explosive demolition techniques. Holes (28) of 1.5" diameter will be drilled into the concrete with track drills, the holes loaded with explosives, and the next layer of concrete blown off. An oxyacetylene torch will be used for cutting concrete rebar or other miscellaneous structural steel. Reinforcing is assumed to be No. 9 rebar (1.25 in dia.) on 12 inch centers. Each sequence will remove 33 cu yd of concrete. The rubble will be pushed aside as required to provide access for the next shot; all rubble will be used on site for fill as required.

2. EQUIPMENT AND MATERIALS REQUIRED

* Blasting Mats
* Crane (55-ton Capacity)
* Air compressor
* Front-end Loader W/Backhoe
* Oxyacetylene Torch
* Track Drill
* Truck (12-ton Capacity)

3. CALCULATIONS

Activity Duration

Required Operations		Activity Duration (minutes)	Critical[1] Duration (minutes)
a.	Check equip (drills, compressor, fog spray, blast mats, etc.	15	15
b.	Position drilling equipment	15	(a)
c.	Drill holes on 2' x 2' centers, 2.5 ft deep, 14' x 16' area	120	120
d.	Place charges in holes	60	60
e.	Place blast mats	20	20
f.	Evacuate area and detonate charges	20	20
g.	Verify all charges have been shot	15	15
h.	Remove blasting mats	20	(i)
i.	Cut rebar with torch	60	60
j.	Remove remaining concrete into cavity as fill	60	60
	Totals (Activity/Critical)	405	370

Work Difficulty Factors[2]

Base Activity Duration	370
Work Difficulty Factor Against Base Duration: Height Adjustment (10%)	37
Actual Duration	407
Nonproductive Time Factor Against Actual Duration: Scheduled Work Breaks Adjustment (8.333 %)	34
Total Work Duration	441 min

*** Total Duration = 7.350 hr ***

Labor Cost

Labor Crew	Number	Duration (hours)	Rate ($/hr)	Cost
Laborers	4.00	7.350	$17.23	$ 506.56
Craftsmen	2.00	7.350	$24.25	$ 356.47
Foreman	3.00	7.350	$26.02	$ 573.74
General Foreman	0.75	7.350	$26.02	$ 143.44
Subtotal labor cost				$1,580.21
Overhead & Profit on labor @ 62.600 %				$989.21
Total labor cost				$2,569.42

Equipment and Material Costs

Equipment:	Rate	Cost[3]	Ref.[4]
Blasting mats (6)	$ 2.72	$ 119.95	1
Crane(55-ton capacity)	$43.58	$ 320.31	2
Air compressor(750 CFM)	$15.46	$ 113.63	3
Truck(12-ton capacity)	$17.46	$ 256.66	4
Front-end loader w/backhoe	$10.97	$ 80.63	5
Track drill	$28.32	$ 208.15	6
Materials:			
Gas torch consumables (1 hr)	$ 7.07	$ 7.07	7
Consumables for 55-ton crane	$29.67	$ 218.07	2
Consumables for compressor	$16.07	$ 118.11	3
Consumables for truck (2)	$15.77	$ 231.82	4
Consumables for FE loader	$ 6.48	$ 47.63	5
Track Drill bits (2 hrs)	$17.93	$ 35.86	6

Equipment and Material Costs (Cont.)

Materials (Cont.):	Rate	Cost[3]	Ref.[4]
Explosives (28)	$ 1.35	$ 37.80	8
Blasting caps (28)	$ 1.78	$ 49.84	9
Subtotal Cost of Equipment and Materials		$1,845.53	
Overhead & Profit on Equipment and Materials @ 15.000 %		$ 276.83	
Total Costs, Equipment & Material		$2,122.36	
SUBTOTAL		$4,691.78	

To convert from: $/sequence @ 33 cu yd/sequence
to: $/cu yd, divide total by 33

TOTAL UNIT COST FACTOR:
Removal of Heavily Reinforced
Concrete w/#9 rebar, $ 142.18 per cu yd

NOTES:

1. Durations are shown in minutes. The critical duration accounts for those activities that can be performed in conjunction with other activities, indicated by the alpha designator of the concurrent activity.

2. Work difficulty factors are delineated in the AIF "Guidelines" (Ref. 2, p 63).

3. Adjusted for regional material costs; average for Indianapolis, Evansville and Terre Haute, IN, 98.9%.

4. Unit Cost Factor Development References:
    1. R.S.Means(1993) Division 022 Section 234-4000, p.41
    2. R.S.Means(1993) Division 016 Section 460-2600, p.20
    3. R.S.Means(1993) Division 016 Section 420-0700, p.16
    4. R.S.Means(1993) Division 016 Section 408-5250, p.16
    5. R.S.Means(1993) Division 016 Section 408-0400, p.15

6. R.S.Means(1993) Crew B-47, p.15

7. R.S.Means(1993) Division 016 Section 420-6360, p.19
8. R.S.Means(1993) Division 022 Section 234-3700, p.42
9. R.S.Means(1993) Division 022 Section 234-3500, p.42

APPENDIX D

UNIT COST FACTOR LISTING

APPENDIX D

UNIT COST FACTOR LISTING

Description	Value ($)
Removal of instrument and sampling tubing, $/linear foot	0.29
Removal of pipe 0.25 to 2 inches diameter $/linear foot	5.30
Removal of pipe >2 to 4 inches diameter $/linear foot	6.34
Removal of pipe >4 to 8 inches diameter $/linear foot	8.59
Removal of pipe >8 to 14 inches diameter $/linear foot	16.56
Removal of pipe >14 to 20 inches diameter $/linear foot	21.69
Removal of pipe >20 to 36 inches diameter $/linear foot	31.75
Removal of pipe >36 inches diameter $/linear foot	37.75
Removal of valves >2 to 4 inches	63.44
Removal of valves >4 to 8 inches	85.87
Removal of valves >8 to 14 inches	150.60
Removal of valves >14 to 20 inches	216.87
Removal of valves >20 to 36 inches	317.53
Removal of valves >36 inches	377.49
Removal of pipe fittings > 2 to 4 inches	63.44
Removal of pipe fittings > 4 to 8 inches	110.25
Removal of pipe fittings > 8 to 14 inches	165.61
Removal of pipe fittings > 14 to 20 inches	216.87
Removal of pipe fittings > 20 to 36 inches	317.53
Removal of pipe fittings > 36 inches	377.49
Removal of pipe hangers for small bore piping	18.53
Removal of pipe hangers for large bore piping	66.38
Removal of pumps, <300 pound	157.83
Removal of pumps, 300-1000 pound	397.95
Removal of pumps, 1000-10,000 pound	1,528.28
Removal of pumps, >10,000 pound	3,116.54
Removal of pump motors 300-1000 pounds	145.20
Removal of pump motors 1000-10,000 pounds	674.97
Removal of pump motors > 10,000 pounds	1,520.15
Removal of turbine-driven pumps < 10,000 pounds	2,026.46

APPENDIX D

UNIT COST FACTOR LISTING
(Continued)

Description	Value ($)
Removal of turbine-driven pumps > 10,000 pounds	3,940.64
Removal of turbine generator	109,502.02
Removal of heat exchanger <3000 pound	828.15
Removal of heat exchanger >3000 pound	2,370.22
Removal of feedwater heater/deaerator	5,465.59
Removal of main condenser	277,709.63
Removal of tanks, <300 gallons	203.14
Removal of tanks, 300-3000 gallons	589.25
Removal of tanks, >3000 gallons, $/square foot surface area	5.02
Removal of electrical equipment, <300 pound	87.41
Removal of electrical equipment, 300-1000 pound	306.53
Removal of electrical equipment, 1000-10,000 pound	613.08
Removal of electrical equipment, >10,000 pound	1,342.62
Removal of electrical transformers < 30 tons	1,017.19
Removal of electrical transformers > 30 tons	2,685.24
Removal of standby diesel-generator, <100 kW	951.47
Removal of standby diesel-generator, 100 kW to 1 MW	2,125.08
Removal of standby diesel-generator, >1 MW	4,400.22
Removal of electrical cable tray, $/linear foot	7.41
Removal of electrical conduit, $/linear foot	3.11
Removal of mechanical equipment, <300 pound	87.41
Removal of mechanical equipment, 300-1000 pound	306.53
Removal of mechanical equipment, 1000-10,000 pound	613.08
Removal of mechanical equipment, >10,000 pound	1,342.62
Removal of HVAC equipment, <300 pound	87.41

APPENDIX D

UNIT COST FACTOR LISTING
(Continued)

Description	Value ($)
Removal of HVAC equipment, 300-1000 pound	306.53
Removal of HVAC equipment, 1000-10,000 pound	613.08
Removal of HVAC equipment, >10,000 pound	1,342.62
Removal of HVAC ductwork, $/pound	0.65
Removal/manual flame cut of thin metal components, $/inch-cut	3.25
Asbestos removal (pipe/components), $/cubic foot	3.24
Removal of standard reinforced concrete, $/cubic yard	290.92
Removal of grade slab concrete, $/cubic yard	160.09
Removal of concrete floors, $/cubic yard	190.57
Removal of sections of concrete floors, $/cubic yard	651.74
Removal of heavily rein concrete w/#9 rebar, $/cubic yard	142.18
Removal of heavily rein concrete w/#18 rebar, $/cubic yard	269.85
Removal of monolithic concrete structures, $/cubic yard	533.21
Removal of foundation concrete, $/cubic yard	454.29
Explosive demolition of bulk concrete, $/cubic yard	21.78
Removal of wooden structures $/cubic foot	0.48
Removal of hyperbolic natural draft cooling tower $/cubic foot	12.63
Removal of mechanical draft cooling tower $/cubic foot	1.93
Removal of hollow masonry block wall, $/cubic yard	55.59
Removal of solid masonry block wall, $/cubic yard	55.59
Placement of concrete for below grade voids, $/cubic yard	76.42
Removal of subterranean tunnels/voids, $/linear foot	97.12
Backfill of below grade voids, $/cubic yard	14.04
Excavation, $/cubic yard	2.64
Excavation of submerged concrete rubble, $/cubic yard	9.23

APPENDIX D

UNIT COST FACTOR LISTING
(Continued)

Description	Value ($)
Removal of concrete rubble, $/cubic yard	42.59
Removal of building by volume, $/cubic foot	0.19
Removal of building metal siding, $/square foot	0.99
Asbestos removal (roofing), $/ square foot	3.95
Removal of standard asphalt roofing, $/square foot	1.48
Removal of transite panels, $/square foot	1.20
Removal of overhead cranes/monorails < 10 ton capacity	397.70
Removal of overhead cranes/monorails 10 - 50 ton capacity	1,128.83
Removal of gantry cranes > 50 ton capacity, each	14,991.12
Removal of structural steel, $/pound	0.24
Removal of steel floor grating, $/square foot	2.26
Removal of concrete anchored steel liner, $/square foot	3.77
Placement of scaffolding, $/square foot	3.33
Landscaping with topsoil, $/acre	15,137.92
Landscaping w/o topsoil, $/acre	2,329.83
Removal of steam drums	11,552.53
Removal of water drums	4,289.92
Removal of upper and lower water wall headers	3,236.50
Removal of top-supported boiler membrane, $/pound	0.39
Removal of bottom-supported boiler membrane, $/pound	0.26
Removal of non-asbestos boiler insulation, $/cubic foot	8.25
Removal of asbestos boiler insulation, $/cubic foot	11.63
Removal of boiler interior and/or exterior fire brick, $/cubic yard	224.26
Removal of top-supported boiler flat stud-tube wall, $/linear foot	0.26
Removal of bottom-supported boiler flat stud-tube wall, $/linear foot	0.26

APPENDIX D

UNIT COST FACTOR LISTING
(Continued)

Description	Value ($)
Removal of convection superheater platens	922.76
Removal of radiant superheater platens	389.89
Removal of reheater platens	389.89
Removal of economizer platens	496.98
Removal of 4x6 inch boiler buckstays/vertical supports, $/ton	0.16
Removal of stationary soot blowers	20.60
Removal of retractable soot blowers	196.53
Removal of HVAC ductwork, $/pound	0.19
Removal of non-asbestos HVAC ductwork insulation, $/pound	1.89
Removal of non-asbestos insulated regenerative air preheaters	5,847.97
Removal of non-insulated regenerative air preheaters	5,557.70
Removal of non-asbestos insulated recuperative air preheaters	3,238.60
Removal of non-insulated recuperative air preheaters	2,977.79
Removal of draft fans	934.53
Removal of coal car dumpers	8,810.77
Removal of conveyors, $/linear foot	7.83
Removal of transfer towers, $/cubic foot	0.10
Removal of stacker-reclaimers	92,880.69
Removal of coal crushers	574.68
Removal of coal hoppers, $/square foot	0.19
Removal of ball mills	830.77
Removal of coal feeders, $/linear foot	201.08

APPENDIX E

UNIT COST FACTOR BASES

APPENDIX E

UNIT COST FACTOR BASES

(All Costs in 1993 Dollars)

1. Craft labor rates; base wages plus fringes - assumed to be an average of the rates for all three stations.

Craft	Cost ($/hr)
- Laborer	17.23
- Craftsmen	24.25
- Foreman	26.02

2. Demolition Operations Contractor (DOC) overhead and profit on labor:

   The DOC would add approximately a 21.2% (15.0% on fully loaded rate) markup to the subcontractor's 41.4% average overhead and profit for subcontracted labor. Therefore, the total markup on base wages plus fringes would be approximately 62.6%.

3. DOC overhead & profit on equipment and materials:

   When purchasing equipment and/or materials, the DOC would add a 15% markup to account for administrative costs.

4. Regional adjustment multiplier for equipment and materials assumed to be an average of the multipliers for the following areas:

Indianapolis, IN vs. National Average	1.013
Evansville, IN vs. National Average	1.034

Terre Haute, IN vs. National Average	0.921
Average Multiplier vs. National Average	0.989

5. Length of Workday: 480 minutes

6. Work Adjustment Factors:

The following factors increase the duration or difficulty of the work and are applied to the activity duration.

a. Height Factor, 12-20' 10.0%

This factor takes into account time necessary for the crew to climb up to the working platform of the scaffold, lift or pass tools/equipment to the platform, and to reverse the steps upon completion of the activity. In addition, it allows for the difficulty of reaching beyond the scaffold to perform the required work.

b. Breathing mask factor 10.0%

Worker efficiency will be adversely affected by the use of canister filter masks. This mask, while providing protection from airborne contaminants resulting in dismantling activities, restricts peripheral vision, free breathing and rapid coordinated motion.

c. Protective clothing factor 0.208%

A factor accounting for the use of protective clothing, the associated procedural "suit-up", and controlled disposal of the clothing. The estimate is based on the productive time lost during eight protective clothing changes per day for the start and end of the day, breaks and lunch.

d. Hazardous work factor 10.0%

A factor addressing the administrative controls and requirements of working in hazardous areas such as increased time consumed in prework briefings and possible debriefings.

e. Paid lost time factor 8.333%

Paid nonproductive time, necessitated by agreement with labor for scheduled work breaks at predetermined intervals.

APPENDIX F

H.T. PRITCHARD GENERATING STATION
DETAILED COST TABLES

FOSSIL STATION DISMANTLING ESTIMATE

H.T. Pritchard Generating Station
Indianapolis Power and Light Company
Wednesday, February 23, 1994

Costs stated in thousands of 1993 dollars unless otherwise noted.
Columns may not total due to rounding.
Identical values may indicate cost sharing with otherunits.
93.12.28 DECCER Version
20:29:32 TIME OF RUN

Scrap Value:

Copper	$1,100.00	per ton
Stainless Steel	$240.00	per ton
Carbon Steel	$100.00	per ton

TABLE 1
H.T. Pritchard Generating Station
Dismantling Cost Summary
1993 Dollars

Dismantling Activity Cost	$21,213,970
Period - Dependent Cost	$10,640,869
Subtotal	$31,854,840
Contingency	$5,080,376
Cost Subtotal	$36,935,216
Scrap Credit	($10,872,095)
Total Project Cost	**$26,063,121**

TABLE 3
H.T. Pritchard Generating Station
Accounts Summary
Thousands of 1993 Dollars

Plant Type	Plant Dismantling Cost	Period Dependent Cost	Scrap Credit	Total
Steam Plant	$24,706	$12,222	($10,868)	$26,059
Diesel-Generators	$5	$3	($4)	$4
Totals Across Plant Types	$24,711	$12,224	($10,872)	$26,063

TABLE 2
H.T. Pritchard Generating Station
Dismantling Activity Cost Summary
Thousands of 1993 Dollars

Activity	Costs	Percent
Asbestos Abatement	$3,934	10.65%
Systems Removal	$9,652	26.13%
Structures Demolition	$7,122	19.28%
Site Restoration	$3,178	8.60%
Utility Staffing	$4,197	11.36%
DOC Staffing	$4,232	11.46%
Liability Insurance	$278	0.75%
Tools & Equipment	$4,344	11.76%
Total Dismantling Costs	$36,935	100.00%
Scrap Credit	($10,872)	
Total Project Cost	$26,063	

TABLE 4
H.T. Pritchard Generating Station
Scrap Value by Plant Type
1993 Dollars

Plant Type	Carbon Stl (tons)	Stainless Stl (tons)	Copper (tons)	Value
Steam Plant	40,718.12	1,741.44	5,798.59	$10,868,212
Diesel-Generators	25.05		1.25	$3,883
Totals	40,743.17	1,741.44	5,799.85	$10,872,095

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
1	PERIOD 1								
1.1	Period 1 Undistributed Costs								
1.1.1	Insurance		71.8	7.2	79.0				
1.1	Subtotal Undistributed Costs Period 1		71.8	7.2	79.0				
1.2	Period 1 Staff Costs								
1.2.1	DOC Staff Cost		824.9	123.7	948.6				
1.2.2	Utility Staff Cost		884.8	132.7	1,017.5				
1.2	Subtotal Staff Costs Period 1		1,709.7	256.5	1,966.1				
1	**TOTAL PERIOD 1 COST**		**1,781.5**	**263.6**	**2,045.1**				
Period 1 Costs Breakdown by Unit									
	Unit 1		**215.3**	**31.9**	**247.2**				
	Unit 2		**215.3**	**31.9**	**247.2**				
	Unit 3		**215.3**	**31.9**	**247.2**				
	Unit 4		**323.0**	**47.8**	**370.8**				
	Unit 5		**323.0**	**47.8**	**370.8**				
	Unit 6		**489.4**	**72.4**	**561.8**				
Period 1 Station Totals			1,781.5	263.6	2,045.1				
2	**PERIOD 2**								
2.1	**Asbestos Abatement**								
2.1.1	Unit 1	636.6	9.3	161.5	807.5				
2.1.2	Unit 2	636.6	9.3	161.5	807.5				
2.1.3	Unit 3	559.1	8.5	141.9	709.6				
2.1.4	Unit 4	460.6	7.5	117.0	585.1				
2.1.5	Unit 5	460.6	7.5	117.0	585.1				
2.1.6	Unit 6	345.0	6.4	87.8	439.2				
2.1	Station Total	3,098.5	48.6	786.8	3,933.9				
2.2	**Removal of Plant Systems**								
2.2.1	UNIT 1								
2.2.1.1	Acid, Caustic and Boiler Chemical Feed	5.8		0.9	6.7	7.0	0.7	0.0	168.2
2.2.1.2	Boiler Feedwater	235.3		35.3	270.6	1,779.8	162.8		7,086.3
2.2.1.3	Circulating Water	102.4		15.4	117.7	532.3	10.8	50.5	2,998.4
2.2.1.4	Coal Handling/Supply	108.9		16.3	125.3	387.6	7.9	51.4	3,163.2
2.2.1.5	Combustion Air and Flue Gas	38.9		5.8	44.7	146.3	12.9		1,093.9
2.2.1.6	Compressed Air	12.0		1.8	13.8	11.4	0.5		353.9
2.2.1.7	Condensate	13.6		2.0	15.7	12.5	1.4		382.7
2.2.1.8	Condenser Air Removal	42.9		6.4	49.4	343.0	0.3	16.0	1,282.4
2.2.1.9	Diesel/Gas Turbine Generator	0.7		0.1	0.8	4.2		0.2	20.5
2.2.1.10	Drains	25.0		3.8	28.8	116.3	33.8	0.5	723.1
2.2.1.11	Electrical System	230.7		34.6	265.4	706.7		746.6	6,731.0
2.2.1.12	Equipment Cooling Water	48.6		7.3	55.9	188.3	50.0	2.0	1,406.4
2.2.1.13	Fuel Oil Supply	2.1		0.3	2.4	3.0	0.1	0.2	59.2
2.2.1.14	Hydrogen and Carbon Dioxide	0.3		0.1	0.4	0.5		0.1	10.4
2.2.1.15	Lubricating Oil	2.3		0.3	2.6	3.1	0.2	0.3	64.8
2.2.1.16	Main Steam, Hot and Cold Reheat	70.3		10.5	80.9	322.1	48.0		2,062.9
2.2.1.17	Seal Water	13.4		2.0	15.4	11.2	0.2	0.5	395.4
2.2.1.18	Vents	3.5		0.5	4.0	6.6			102.3
2.2.1	Unit 1 Totals	959.1		143.9	1,102.9	4,584.5	329.7	870.3	28,167.9
2.2.2	UNIT 2								
2.2.2.1	Acid, Caustic and Boiler Chemical Feed	5.8		0.9	6.7	7.0	0.7	0.0	168.2
2.2.2.2	Boiler Feedwater	235.3		35.3	270.6	1,779.8	162.8		7,086.3
2.2.2.3	Circulating Water	102.4		15.4	117.7	532.3	10.8	50.5	2,998.4

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
2.2.2.4	Coal Handling/Supply	108.9		16.3	125.3	387.6	7.9	51.4	3,163.2
2.2.2.5	Combustion Air and Flue Gas	38.9		5.8	44.7	146.3	12.9		1,093.9
2.2.2.6	Compressed Air	12.0		1.8	13.8	11.4	0.5		353.9
2.2.2.7	Condensate	13.6		2.0	15.7	12.5	1.4		382.7
2.2.2.8	Condenser Air Removal	42.9		6.4	49.4	343.0	0.3	16.0	1,282.4
2.2.2.9	Diesel/Gas Turbine Generator	0.7		0.1	0.8	4.2		0.2	20.5
2.2.2.10	Drains	25.0		3.8	28.8	116.3	33.8	0.5	723.1
2.2.2.11	Electrical System	230.7		34.6	265.4	706.7		748.6	6,731.0
2.2.2.12	Equipment Cooling Water	48.6		7.3	55.9	188.3	50.0	2.0	1,406.4
2.2.2.13	Fuel Oil Supply	2.1		0.3	2.4	3.0	0.1	0.2	59.2
2.2.2.14	Hydrogen and Carbon Dioxide	0.3		0.1	0.4	0.5		0.1	10.4
2.2.2.15	Lubricating Oil	2.3		0.3	2.6	3.1	0.2	0.3	64.8
2.2.2.16	Main Steam, Hot and Cold Reheat	70.3		10.5	80.9	322.1	48.0		2,062.9
2.2.2.17	Seal Water	13.4		2.0	15.4	11.2	0.2	0.5	395.4
2.2.2.18	Vents	3.5		0.5	4.0	6.6			102.3
2.2.2	Unit 2 Totals	959.1		143.9	1,102.9	4,584.5	329.7	870.3	28,167.9
2.2.3	UNIT 3								
2.2.3.1	Acid, Caustic and Boiler Chemical Feed	5.8		0.9	6.7	7.0	0.7	0.0	168.2
2.2.3.2	Boiler Feedwater	238.2		35.7	274.0	1,779.8	162.8		7,179.7
2.2.3.3	Circulating Water	102.4		15.4	117.7	532.3	10.8	50.5	2,998.4
2.2.3.4	Coal Handling/Supply	108.9		16.3	125.3	387.6	7.9	51.4	3,163.2
2.2.3.5	Combustion Air and Flue Gas	38.9		5.8	44.7	146.3	12.9		1,093.9
2.2.3.6	Compressed Air	12.0		1.8	13.8	11.4	0.5		353.9
2.2.3.7	Condensate	13.6		2.0	15.7	12.5	1.4		382.7
2.2.3.8	Condenser Air Removal	42.9		6.4	49.4	343.0	0.3	16.0	1,282.4
2.2.3.9	Diesel/Gas Turbine Generator	0.7		0.1	0.8	4.2		0.2	20.5
2.2.3.10	Drains	25.0		3.8	28.8	116.3	33.8	0.5	723.1
2.2.3.11	Electrical System	230.7		34.6	265.4	706.7		748.6	6,731.0
2.2.3.12	Equipment Cooling Water	48.6		7.3	55.9	188.3	50.0	2.0	1,406.4
2.2.3.13	Fuel Oil Supply	2.1		0.3	2.4	3.0	0.1	0.2	59.2
2.2.3.14	Hydrogen and Carbon Dioxide	0.3		0.1	0.4	0.5		0.1	10.4
2.2.3.15	Lubricating Oil	2.3		0.3	2.6	3.1	0.2	0.3	64.8
2.2.3.16	Main Steam, Hot and Cold Reheat	70.3		10.5	80.9	322.1	48.0		2,062.9
2.2.3.17	Seal Water	13.4		2.0	15.4	11.2	0.2	0.5	395.4
2.2.3.18	Vents	3.5		0.5	4.0	6.6			102.3
2.2.3	Unit 3 Totals	962.0		144.3	1,106.3	4,584.5	329.7	870.3	28,261.3
2.2.4	UNIT 4								
2.2.4.1	Acid, Caustic and Boiler Chemical Feed	5.8		0.9	6.7	7.0	0.7	0.0	168.2
2.2.4.2	Boiler Feedwater	284.2		42.6	326.9	858.3	54.2		8,664.3
2.2.4.3	Circulating Water	113.9		17.1	131.0	544.0	10.8	50.5	3,344.4
2.2.4.4	Coal Handling/Supply	142.3		21.3	163.7	470.4	12.9	56.9	4,147.5
2.2.4.5	Combustion Air and Flue Gas	18.1		2.7	20.9	127.4	10.8		511.2
2.2.4.6	Compressed Air	15.6		2.3	18.0	12.6	0.5		461.9
2.2.4.7	Condensate	33.7		5.1	38.8	33.2	1.4	1.5	974.4
2.2.4.8	Condenser Air Removal	50.0		7.5	57.5	358.1	0.3	16.0	1,500.6
2.2.4.9	Diesel/Gas Turbine Generator	0.7		0.1	0.8	4.2		0.2	20.5
2.2.4.10	Drains	25.0		3.8	28.8	116.3	33.8	0.5	723.1
2.2.4.11	Electrical System	230.7		34.6	265.4	706.7		748.6	6,731.0
2.2.4.12	Equipment Cooling Water	53.9		8.1	61.9	190.9	50.0	2.0	1,562.6
2.2.4.13	Fuel Oil Supply	227.3		34.1	261.4	753.8	0.1	167.0	6,619.1
2.2.4.14	Hydrogen and Carbon Dioxide	0.3		0.1	0.4	0.5		0.1	10.4
2.2.4.15	Lubricating Oil	2.3		0.3	2.6	3.1	0.2	0.3	64.8
2.2.4.16	Main Steam, Hot and Cold Reheat	106.5		16.0	122.5	399.7	59.1		3,134.5
2.2.4.17	Seal Water	17.0		2.6	19.6	20.7	0.2	1.5	499.7
2.2.4.18	Vents	4.5		0.7	5.2	7.8			132.6
2.2.4	UNIT 4 Totals	1,334.3		200.1	1,534.5	4,617.1	235.1	1,045.2	39,333.1
2.2.5	UNIT 5								
2.2.5.1	Acid, Caustic and Boiler Chemical Feed	5.8		0.9	6.7	7.0	0.7	0.0	168.2
2.2.5.2	Boiler Feedwater	284.2		42.6	326.9	858.3	54.2		8,664.3
2.2.5.3	Circulating Water	113.9		17.1	131.0	544.0	10.8	50.5	3,344.4
2.2.5.4	Coal Handling/Supply	142.3		21.3	163.7	470.4	12.9	56.9	4,147.5

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
2.2.5.5	Combustion Air and Flue Gas	18.1		2.7	20.9	127.4	10.8		511.2
2.2.5.6	Compressed Air	15.6		2.3	18.0	12.8	0.5		481.9
2.2.5.7	Condensate	33.7		5.1	38.8	33.2	1.4	1.5	974.4
2.2.5.8	Condenser Air Removal	50.0		7.5	57.5	358.1	0.3	18.0	1,500.0
2.2.5.9	Diesel/Gas Turbine Generator	0.7		0.1	0.8	4.2		0.2	20.5
2.2.5.10	Drains	25.0		3.8	28.8	116.3	33.8	0.5	723.1
2.2.5.11	Electrical System	230.7		34.6	265.4	706.7		746.6	6,731.0
2.2.5.12	Equipment Cooling Water	53.9		8.1	61.9	190.9	50.0	2.0	1,562.6
2.2.5.13	Fuel Oil Supply	227.3		34.1	261.4	753.8	0.1	167.0	6,619.1
2.2.5.14	Hydrogen and Carbon Dioxide	0.3		0.1	0.4	0.5		0.1	10.4
2.2.5.15	Lubricating Oil	2.3		0.3	2.8	3.1	0.2	0.3	64.6
2.2.5.16	Main Steam, Hot and Cold Reheat	106.5		16.0	122.5	399.7	59.1		3,134.5
2.2.5.17	Seal Water	17.0		2.6	19.6	20.7	0.2	1.5	499.7
2.2.5.18	Vents	4.5		0.7	5.2	7.8			132.6
2.2.5	UNIT 5 Totals	1,334.3		200.1	1,534.5	4,617.1	235.1	1,045.2	39,333.1
2.2.6	UNIT 6								
2.2.6.1	Acid, Caustic and Boiler Chemical Feed	6.6		1.0	7.6	8.6	0.8	0.0	191.4
2.2.6.2	Boiler Feedwater	269.6		40.4	310.1	1,986.6	112.2	0.0	8,209.8
2.2.6.4	Circulating Water	207.6		31.1	238.8	315.6	16.8	11.8	6,060.4
2.2.6.5	Coal Handling/Supply	271.7		40.8	312.5	724.8	12.9	66.4	7,975.2
2.2.6.6	Combustion Air and Flue Gas	43.5		6.5	50.0	150.5	13.4		1,223.1
2.2.6.7	Compressed Air	28.5		4.3	32.8	21.4	0.0		845.6
2.2.6.8	Condensate	45.1		6.8	51.9	36.5	0.8	1.5	1,322.1
2.2.6.9	Condenser Air Removal	68.4		10.3	78.6	397.9	0.3	18.0	2,060.1
2.2.6.10	Diesel/Gas Turbine Generator	0.7		0.1	0.8	4.2		0.2	20.5
2.2.6.11	Drains	64.9		9.7	74.6	172.1	43.8	0.5	1,698.2
2.2.6.12	Electrical System	230.7		34.6	265.4	706.7		748.6	6,731.0
2.2.6.13	Equipment Cooling Water	62.3		9.4	71.7	194.7	50.0	2.0	1,813.8
2.2.6.14	Fuel Oil Supply	737.2		110.6	847.8	1,671.3	0.1	187.0	21,393.1
2.2.6.15	Hydrogen and Carbon Dioxide	2.5		0.4	2.9	7.0		0.3	71.2
2.2.6.16	Lubricating Oil	2.3		0.3	2.6	3.1	0.2	0.3	64.8
2.2.6.17	Main Steam, Hot and Cold Reheat	76.8		11.5	88.3	185.9	30.3		2,269.8
2.2.6.18	Seal Water	19.0		2.9	21.9	14.1	0.3	0.5	559.5
2.2.6.19	Vents	5.7		0.9	6.6	9.1			168.9
2.2.6	UNIT 6 Totals	2,513.1		377.0	2,890.0	7,446.7	282.1	1,098.5	73,608.4
2.2	System Removal Station Totals	8,061.8		1,209.3	9,271.1	30,434.5	1,741.4	5,799.8	236,871.7
2.3	**Removal of Main Turbine / Generator**								
2.3.1	Unit 1	17.4		2.6	20.0	464.6			482.4
2.3.2	Unit 2	17.4		2.6	20.0	464.6			482.4
2.3.3	Unit 3	17.4		2.6	20.0	464.6			482.4
2.3.4	Unit 4	18.4		2.8	21.2	490.8			509.6
2.3.5	Unit 5	18.4		2.8	21.2	490.8			509.6
2.3.6	Unit 6	19.9		3.0	22.9	531.3			551.7
2.3	Station Turbine/Generator Totals	109.0		16.3	125.3	2,906.6			3,018.2
2.4	**Removal of Main Condenser**								
2.4.1	Unit 1	34.0		5.1	39.1	211.5			923.9
2.4.2	Unit 2	34.0		5.1	39.1	211.5			923.9
2.4.3	Unit 3	34.0		5.1	39.1	211.5			923.9
2.4.4	Unit 4	41.6		6.2	47.8	258.5			1,129.3
2.4.5	Unit 5	41.6		6.2	47.8	258.5			1,129.3
2.4.6	Unit 6	36.7		5.5	42.2	228.1			996.6
2.4	Station Condenser Totals	221.9		33.3	255.1	1,379.7			6,026.8
2.5	**Demolition of Remaining Site Buildings**								
2.5.1	Boiler/Turbine Building	5,190.4		778.6	5,969.0	5,565.0			118,930.2
2.5.2	Coal Handling Buildings/Structures	492.6		73.9	566.5	347.1			10,608.2
2.5.3	Cooling Tower Structures	317.0		47.5	364.5	7.0			8,464.2
2.5.4	Crib House/Intake Buildings & Structures	20.8		3.1	23.9	19.1			431.5

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
2.5.5	Other Buildings & Structures	88.6		13.3	101.9	84.2			1,540.5
2.5.6	Stack/Precipitator Structures	84.1		12.6	96.8				1,696.8
2.5	Station Building Demolition Totals	6,193.4		929.0	7,122.5	6,022.4			141,071.1
2.6	**Period 2 Undistributed Costs**								
2.6.1	Insurance		174.6	17.5	192.0				
2.6.2	Heavy equipment rental		3,030.4	454.6	3,484.9				
2.6.3	Pipe cutting equipment		587.2	88.1	675.3				
2.6.4	Small Tool Allowance	120.7		18.1	138.7				
2.6	Subtotal Undistributed Costs Period 2	120.7	3,792.2	578.2	4,491.0				
2.7	**Period 2 Staff Costs**								
2.7.1	DOC Staff Cost		2,817.4	422.6	3,240.0				
2.7.2	Utility Staff Cost		2,752.7	412.9	3,165.7				
2.7	Subtotal Staff Costs Period 2		5,570.1	835.5	6,405.6				
2	**TOTAL PERIOD 2**	**17,805.2**	**9,410.9**	**4,388.4**	**31,604.6**	**40,743.2**	**1,741.4**	**5,799.8**	**387,587.9**
Period 2 Costs Breakdown by Unit									
	Unit 1	**2,410.4**	**1,141.0**	**596.3**	**4,147.6**	**5,988.6**	**329.7**	**870.3**	**46,699.3**
	Unit 2	**2,410.4**	**1,141.0**	**596.3**	**4,147.6**	**5,988.6**	**329.7**	**870.3**	**46,699.3**
	Unit 3	**2,335.8**	**1,140.2**	**577.1**	**4,053.1**	**5,988.8**	**329.7**	**870.3**	**46,792.8**
	Unit 4	**2,999.7**	**1,705.1**	**750.9**	**5,455.6**	**6,456.4**	**235.1**	**1,045.2**	**66,659.6**
	Unit 5	**2,999.7**	**1,705.1**	**750.9**	**5,455.6**	**6,456.4**	**235.1**	**1,045.2**	**66,659.6**
	Unit 6	**4,649.3**	**2,578.4**	**1,116.9**	**8,344.6**	**9,860.6**	**262.1**	**1,098.5**	**114,077.2**
Period 2 Station Totals		17,805.2	9,410.9	4,388.4	31,604.6	40,743.2	1,741.4	5,799.8	387,587.9
3	PERIOD 3								
3.1	Site Closeout Activities								
3.1.1	BackFill Site	501.6		75.2	576.9				2,751.2
3.1.2	Site Restoration	2,262.1		339.3	2,601.4				764.2
3.1	Station Closeout Totals	2,763.7		414.6	3,178.3				3,515.4
3.2	Period 3 Undistributed Costs								
3.2.1	Insurance		4.9	0.5	5.4				
3.2.2	Heavy equipment rental		29.7	4.5	34.2				
3.2.4	Small Tool Allowance	9.2		1.4	10.5				
3.2	Subtotal Undistributed Costs Period 3	9.2	34.6	6.3	50.1				
3.3	Staff Costs Period 3								
3.3.1	DOC Staff Cost		37.9	5.7	43.6				
3.3.2	Utility Staff Cost		11.6	1.8	13.6				
3.3	Subtotal Staff Costs Period 3		49.7	7.5	57.2				
TOTAL PERIOD 3		**2,772.9**	**84.3**	**428.3**	**3,285.5**				**3,515.4**
Period 3 Costs Breakdown by Unit									
	Unit 1	**335.2**	**10.2**	**51.6**	**397.2**				**424.9**
	Unit 2	**335.2**	**10.2**	**51.6**	**397.2**				**424.9**
	Unit 3	**335.2**	**10.2**	**51.6**	**397.2**				**424.9**
	Unit 4	**502.8**	**15.3**	**77.7**	**595.7**				**637.4**
	Unit 5	**502.8**	**15.3**	**77.7**	**595.7**				**637.4**
	Unit 6	**781.6**	**23.2**	**117.7**	**902.6**				**965.8**
Period 3 Station Totals		**2,772.9**	**84.3**	**428.3**	**3,285.5**				**3,515.4**
TOTAL COST TO DISMANTLE		**20,578.1**	**11,278.7**	**5,080.4**	**38,935.2**	**40,743.2**	**1,741.4**	**5,799.8**	**391,103.3**

Activity Number	Activity Description	Removal $		Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
Total Expenditures to Dismantle with 15.95% Contingency:						$36,935,217				
	1993 Dollars									
Credit for Scrap Metal Removed.										
	Carbon Steel Scrap Tonnage	40,743	@$100.00 / ton		$4,074,317					
	Stainless Steel Scrap Tonnage	1,741	@$240.00 / ton		$417,946					
	Copper Scrap Tonnage	5,800	@$1100.00 / ton		$6,379,832					
	Total Scrap Metal Credit	48,284.5	Tons			($10,872,095)				
Estimated Adjusted Cost to Utility to Dismantle:						$26,063,122				
TOTAL CRAFT LABOR REQUIREMENTS:						391,103.3	MAN-HOURS			

TOTAL COST TO DISMANTLE BREAKDOWN BY UNIT	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
Unit 1	2,745.5	1,366.6	679.9	4,792.0	5,988.6	329.7	870.3	47,124.3
Unit 2	2,745.5	1,366.8	679.9	4,792.0	5,988.8	329.7	870.3	47,124.3
Unit 3	2,870.9	1,365.8	660.8	4,697.5	5,988.6	329.7	870.3	47,217.7
Unit 4	3,502.5	2,043.4	876.4	6,422.3	8,456.4	235.1	1,045.2	67,297.0
Unit 5	3,502.5	2,043.4	876.4	6,422.3	8,458.4	235.1	1,045.2	67,297.0
Unit 6	5,411.1	3,091.0	1,307.0	9,809.1	9,860.8	282.1	1,098.5	115,043.0
Total Cost for All Units	20,578.1	11,276.7	5,080.4	36,935.2	40,743.2	1,741.4	5,799.8	391,103.3

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours

UNIT BREAKDOWN (1993 Dollars)	UNIT 1		UNIT 2		UNIT 3		UNIT 4	
Total Expenditures to Dismantle by Unit		$4,792,005		$4,792,005		$4,697,489		$6,422,311
Contingency		16.53%		16.53%		16.37%		15.80%
Credit for Scrap Metal Removed:								
Carbon steel scrap @ $100.00 / ton	5,989	$598,859	5,989	$598,859	5,989	$598,859	6,458	$645,840
Stainless steel scrap @ $240.00 / ton	330	$79,136	330	$79,136	330	$79,136	235	$56,415
Copper scrap @ $1100.00 / ton	870	$957,372	870	$957,372	870	$957,372	1,045	$1,149,688
Total Scrap Metal Credit	7,188.7	($1,635,366)	7,188.7	($1,635,366)	7,188.7	($1,635,366)	7,738.6	($1,851,943)
Estimated Adjusted Cost to Utility to Dismantle:		$3,156,640		$3,156,640		$3,062,123		$4,570,368
TOTAL CRAFT LABOR REQUIREMENTS		47,124.3		47,124.3		47,217.7		67,297.0

UNIT BREAKDOWN (1993 Dollars)	UNIT 5		UNIT 6	
Total Expenditures to Dismantle by Unit		$6,422,311		$9,809,097
Contingency		15.80%		15.37%
Credit for Scrap Metal Removed:				
Carbon steel scrap @ $100.00 / ton	8,458	$645,840	9,861	$986,061
Stainless steel scrap @ $240.00 / ton	235	$56,415	282	$67,710
Copper scrap @ $1100.00 / ton	1,045	$1,149,688	1,098	$1,208,341
Total Scrap Metal Credit	7,738.6	($1,851,943)	11,241.2	($2,262,113)
Estimated Adjusted Cost to Utility to Dismantle:		$4,570,368		$7,546,984
TOTAL CRAFT LABOR REQUIREMENTS		67,297.0		115,043.0

APPENDIX G

E.W. STOUT GENERATING STATION
DETAILED COST TABLES

FOSSIL STATION DISMANTLING ESTIMATE

E.W. Stout Generating Station
Indianapolis Power and Light Company
Wednesday, February 23, 1994

Costs stated in thousands of 1993 dollars unless otherwise noted.
Columns may not total due to rounding.
Identical values may indicate cost sharing with other units.
93.12.28 DECCER Version
19:51:57 TIME OF RUN

Scrap Value:

Copper	$1,100.00	per ton
Stainless Steel	$240.00	per ton
Carbon Steel	$100.00	per ton

TABLE 1

E.W. Stout Generating Station
Dismantling Cost Summary

1993 Dollars

Dismantling Activity Cost	$32,454,555
Period - Dependent Cost	$10,789,887
Subtotal	$43,244,442
Contingency	$6,763,829
Cost Subtotal	$50,008,271
Scrap Credit	($17,474,367)
Total Project Cost	**$32,533,904**

TABLE 3

E.W. Stout Generating Station
Accounts Summary

Thousands of 1993 Dollars

Plant Type	Plant Dismantling Cost	Period Dependent Cost	Scrap Credit	Total
Steam Plant	$37,602	$12,380	($17,459)	$32,523
Combustion Turbines	$10	$3	($8)	$6
Diesel-Generators	$10	$3	($8)	$6
Totals Across Plant Types	$37,622	$12,388	($17,474)	$32,534

TABLE 2

E.W. Stout Generating Station
Dismantling Activity Cost Summary

Thousands of 1993 Dollars

Activity	Costs	Percent
Asbestos Abatement	$3,740	7.48%
Systems Removal	$13,885	27.76%
Structures Demolition	$12,058	24.11%
Site Restoration	$7,041	14.08%
Utility Staffing	$4,155	8.31%
DOC Staffing	$4,238	8.47%
Liability Insurance	$485	0.97%
Tools & Equipment	$4,407	8.81%
Total Dismantling Costs	$50,008	100.00%
Scrap Credit	($17,474)	
Total Project Cost	$32,534	

TABLE 4

Scrap Value by Plant Type

1993 Dollars

Plant Type	Carbon Stl (tons)	Stainless Stl (tons)	Copper (tons)	Value
Steam Plant	73,128.42	2,284.52	8,725.23	$17,458,879
Combustion Turbines	49.96		2.50	$7,744
Diesel-Generators	49.96		2.50	$7,744
Totals	73,228.34	2,284.52	8,730.23	$17,474,367

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
1	PERIOD 1								
1.1	Period 1 Undistributed Costs								
1.1.1	Insurance		127.1	12.7	139.8				
1.1	Subtotal Undistributed Costs Period 1		127.1	12.7	139.8				
1.2	Period 1 Staff Costs								
1.2.1	DOC Staff Cost		820.7	123.1	943.8				
1.2.2	Utility Staff Cost		882.1	132.3	1,014.4				
1.2	Subtotal Staff Costs Period 1		1,702.8	255.4	1,958.2				
1	**TOTAL PERIOD 1 COST**		**1,829.8**	**268.1**	**2,097.9**				
Period 1 Costs Breakdown by Unit									
	Unit 1		**86.5**	**12.7**	**99.1**				
	Unit 2		**86.5**	**12.7**	**99.1**				
	Unit 3		**88.2**	**12.9**	**101.1**				
	Unit 4		**88.2**	**12.9**	**101.1**				
	Unit 5		**235.2**	**34.5**	**269.7**				
	Unit 6		**235.2**	**34.5**	**269.7**				
	Unit 7		**1,010.0**	**148.0**	**1,158.0**				
Period 1 Station Totals			1,829.8	268.1	2,097.9				
2	PERIOD 2								
2.1	**Asbestos Abatement**								
2.1.1	Unit 1	334.2	9.2	85.9	429.3				12,913.5
2.1.2	Unit 2	334.2	9.2	85.9	429.3				12,913.5
2.1.3	Unit 3	623.7	8.7	158.1	790.5				24,097.0
2.1.4	Unit 4	623.7	8.7	158.1	790.5				24,097.0
2.1.5	Unit 5	575.4	5.9	145.3	726.5				16,755.2
2.1.6	Unit 6	433.7	5.9	109.9	549.4				16,755.2
2.1.7	Unit 7	16.6	3.1	4.9	24.5				640.3
2.1	Station Total	2,941.5	50.4	748.0	3,739.9				108,171.6
2.2	**Removal of Plant Systems**								
2.2.1	UNIT 1								
2.2.1.1	Acid, Caustic and Boiler Chemical Feed	12.2		1.8	14.0	12.1	0.5	0.0	359.5
2.2.1.2	Boiler Feedwater	201.6		30.2	231.9	1,762.8	162.8		6,042.8
2.2.1.3	Circulating Water	93.9		14.1	107.9	538.3	10.2	50.5	2,756.5
2.2.1.4	Coal Handling/Supply	82.1		12.3	94.4	270.3	8.3	16.5	2,373.3
2.2.1.5	Combustion Air and Flue Gas	10.1		1.5	11.6	120.0	10.0		285.6
2.2.1.6	Compressed Air	8.3		1.2	9.5	9.9	0.5		244.2
2.2.1.7	Condensate	6.3		1.0	7.3	7.3	0.3	0.4	181.8
2.2.1.8	Condenser Air Removal	45.1		6.8	51.9	348.6	0.3	16.0	1,350.0
2.2.1.9	Diesel/Gas Turbine Generators	2.5		0.4	2.9	14.3		0.7	70.2
2.2.1.10	Drains	25.9		3.9	29.7	117.2	33.9	0.5	746.8
2.2.1.11	Electrical Systems	259.0		38.8	297.8	1,196.5		1,157.6	7,537.2
2.2.1.12	Equipment Cooling Water	36.5		5.5	42.0	153.8	40.0	2.0	1,053.7
2.2.1.13	Fuel Oil Supply	71.7		10.7	82.4	74.5	6.6	1.5	2,018.9
2.2.1.14	Hydrogen and Carbon Dioxide	3.6		0.5	4.1	8.2		0.5	102.0
2.2.1.15	Lubricating Oil	20.4		3.1	23.5	19.7	2.1	0.3	574.8
2.2.1.16	Main Steam, Hot and Cold Reheat	64.5		9.7	74.1	283.6	33.7		1,898.5
2.2.1.17	Seal Water	5.0		0.7	5.7	11.4	0.2	1.0	145.2
2.2.1.18	Vents	3.2		0.5	3.7	7.5			95.2
2.2.1.19	Waste Treatment	2.5		0.4	2.9	4.0	0.0	0.0	74.1
2.2.1	Unit 1 Totals	954.3		143.1	1,097.5	4,960.0	309.3	1,247.5	27,910.2
2.2.2	UNIT 2								
2.2.2.1	Acid, Caustic and Boiler Chemical Feed	12.2		1.8	14.0	12.1	0.5	0.0	359.5
2.2.2.2	Boiler Feedwater	201.6		30.2	231.9	1,762.8	162.8		6,042.8
2.2.2.3	Circulating Water	93.9		14.1	107.9	538.3	10.2	50.5	2,756.5
2.2.2.4	Coal Handling/Supply	82.1		12.3	94.4	270.3	8.3	16.5	2,373.3
2.2.2.5	Combustion Air and Flue Gas	10.1		1.5	11.6	120.0	10.0		285.6

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
2.2.2.6	Compressed Air	8.3		1.2	9.5	9.9	0.5		244.2
2.2.2.7	Condensate	6.3		1.0	7.3	7.3	0.3	0.4	181.8
2.2.2.8	Condenser Air Removal	45.1		6.8	51.9	348.6	0.3	16.0	1,350.0
2.2.2.9	Diesel/Gas Turbine Generators	2.5		0.4	2.9	14.3		0.7	70.2
2.2.2.10	Drains	25.9		3.9	29.7	117.2	33.9	0.5	746.8
2.2.2.11	Electrical Systems	259.0		38.8	297.8	1,196.5		1,157.6	7,537.2
2.2.2.12	Equipment Cooling Water	36.5		5.5	42.0	153.8	40.0	2.0	1,053.7
2.2.2.13	Fuel Oil Supply	71.7		10.7	82.4	74.5	6.6	1.5	2,018.9
2.2.2.14	Hydrogen and Carbon Dioxide	3.6		0.5	4.1	8.2		0.5	102.0
2.2.2.15	Lubricating Oil	20.4		3.1	23.5	19.7	2.1	0.3	574.8
2.2.2.16	Main Steam, Hot and Cold Reheat	64.5		9.7	74.1	283.6	33.7		1,898.5
2.2.2.17	Seal Water	5.0		0.7	5.7	11.4	0.2	1.0	145.2
2.2.2.18	Vents	3.2		0.5	3.7	7.5			95.2
2.2.2.19	Waste Treatment	2.5		0.4	2.9	4.0	0.0	0.0	74.1
2.2.2	Unit 2 Totals	954.3		143.1	1,097.5	4,960.0	309.3	1,247.5	27,910.2
2.2.3	UNIT 3								
2.2.3.1	Acid, Caustic and Boiler Chemical Feed	12.2		1.8	14.0	12.1	0.5	0.0	359.5
2.2.3.2	Boiler Feedwater	201.6		30.2	231.9	1,762.8	162.8		6,042.8
2.2.3.3	Circulating Water	93.9		14.1	107.9	538.3	10.2	50.5	2,756.5
2.2.3.4	Coal Handling/Supply	82.1		12.3	94.4	270.3	8.3	16.5	2,373.3
2.2.3.5	Combustion Air and Flue Gas	10.1		1.5	11.6	120.0	10.0		285.6
2.2.3.6	Compressed Air	8.3		1.2	9.5	9.9	0.5		244.2
2.2.3.7	Condensate	6.3		1.0	7.3	7.3	0.3	0.4	181.8
2.2.3.8	Condenser Air Removal	45.1		6.8	51.9	348.6	0.3	16.0	1,350.0
2.2.3.9	Diesel/Gas Turbine Generators	2.5		0.4	2.9	14.3		0.7	70.2
2.2.3.10	Drains	25.9		3.9	29.7	117.2	33.9	0.5	746.8
2.2.3.11	Electrical Systems	259.0		38.8	297.8	1,196.5		1,157.6	7,537.2
2.2.3.12	Equipment Cooling Water	36.5		5.5	42.0	153.8	40.0	2.0	1,053.7
2.2.3.13	Fuel Oil Supply	71.7		10.7	82.4	74.5	6.6	1.5	2,018.9
2.2.3.14	Hydrogen and Carbon Dioxide	3.6		0.5	4.1	8.2		0.5	102.0
2.2.3.15	Lubricating Oil	20.4		3.1	23.5	19.7	2.1	0.3	574.8
2.2.3.16	Main Steam, Hot and Cold Reheat	64.5		9.7	74.1	283.6	33.7		1,898.5
2.2.3.17	Seal Water	5.0		0.7	5.7	11.4	0.2	1.0	145.2
2.2.3.18	Vents	3.2		0.5	3.7	7.5			95.2
2.2.3.19	Waste Treatment	2.5		0.4	2.9	4.0	0.0	0.0	74.1
2.2.3	Unit 3 Totals	954.3		143.1	1,097.5	4,960.0	309.3	1,247.5	27,910.2
2.2.4	UNIT 4								
2.2.4.1	Acid, Caustic and Boiler Chemical Feed	12.2		1.8	14.0	12.1	0.5	0.0	359.5
2.2.4.2	Boiler Feedwater	201.6		30.2	231.9	1,762.8	162.8		6,042.8
2.2.4.3	Circulating Water	93.9		14.1	107.9	538.3	10.2	50.5	2,756.5
2.2.4.4	Coal Handling/Supply	82.1		12.3	94.4	270.3	8.3	16.5	2,373.3
2.2.4.5	Combustion Air and Flue Gas	10.1		1.5	11.6	120.0	10.0		285.6
2.2.4.6	Compressed Air	8.3		1.2	9.5	9.9	0.5		244.2
2.2.4.7	Condensate	6.3		1.0	7.3	7.3	0.3	0.4	181.8
2.2.4.8	Condenser Air Removal	45.1		6.8	51.9	348.6	0.3	16.0	1,350.0
2.2.4.9	Diesel/Gas Turbine Generators	2.5		0.4	2.9	14.3		0.7	70.2
2.2.4.10	Drains	25.9		3.9	29.7	117.2	33.9	0.5	746.8
2.2.4.11	Electrical Systems	259.0		38.8	297.8	1,196.5		1,157.6	7,537.2
2.2.4.12	Equipment Cooling Water	36.5		5.5	42.0	153.8	40.0	2.0	1,053.7
2.2.4.13	Fuel Oil Supply	71.7		10.7	82.4	74.5	6.6	1.5	2,018.9
2.2.4.14	Hydrogen and Carbon Dioxide	3.6		0.5	4.1	8.2		0.5	102.0
2.2.4.15	Lubricating Oil	20.4		3.1	23.5	19.7	2.1	0.3	574.8
2.2.4.16	Main Steam, Hot and Cold Reheat	64.5		9.7	74.1	283.6	33.7		1,898.5
2.2.4.17	Seal Water	5.0		0.7	5.7	11.4	0.2	1.0	145.2
2.2.4.18	Vents	3.2		0.5	3.7	7.5			95.2
2.2.4.19	Waste Treatment	2.5		0.4	2.9	4.0	0.0	0.0	74.1
2.2.4	UNIT 4 Totals	954.3		143.1	1,097.5	4,960.0	309.3	1,247.5	27,910.2
2.2.5	UNIT 5								
2.2.5.1	Acid, Caustic and Boiler Chemical Feed	57.0		8.5	65.5	45.9	0.5	2.8	1,680.7
2.2.5.2	Boiler Feedwater	363.8		54.6	418.4	2,211.7	145.6	2.5	10,811.1
2.2.5.3	Circulating Water	180.9		27.1	208.0	473.6	0.3	21.8	5,397.4
2.2.5.4	Coal Handling/Supply	168.3		25.3	193.6	618.9	13.3	31.5	4,921.9
2.2.5.5	Combustion Air and Flue Gas	93.8		14.1	107.9	141.5	13.9	0.3	2,635.6
2.2.5.6	Compressed Air	14.2		2.1	16.3	15.6	0.2		421.4
2.2.5.7	Condensate	11.9		1.8	13.7	16.5	0.3	1.5	344.8

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
2.2.5.8	Condenser Air Removal	59.4		8.9	68.3	379.8	0.3	16.0	1,786.4
2.2.5.9	Diesel/Gas Turbine Generator	2.5		0.4	2.9	14.3		0.7	70.2
2.2.5.10	Drains	29.8		4.5	34.3	146.3	43.8	0.5	858.5
2.2.5.11	Electrical System	259.0		38.8	297.8	1,196.5		1,157.6	7,537.2
2.2.5.12	Equipment Cooling Water	40.0		6.0	46.1	156.0	40.0	2.0	1,158.8
2.2.5.13	Fuel Oil Supply	136.6		20.5	157.1	131.0	13.4	1.0	3,841.8
2.2.5.14	Hydrogen and Carbon Dioxide	0.2		0.0	0.2	0.2			5.2
2.2.5.15	Lubricating Oil	20.4		3.1	23.5	19.7	2.1	0.3	574.8
2.2.5.16	Main Steam, Hot and Cold Reheat	43.2		6.5	49.7	115.3	11.4		1,287.8
2.2.5.17	Seal Water	8.0		1.2	9.2	7.7		0.5	235.2
2.2.5.18	Vents	2.9		0.4	3.3	6.0			86.1
2.2.5.19	Waste Treatment	3.4		0.5	3.9	4.7	0.0	0.0	100.3
2.2.5	UNIT 5 Totals	1,495.3		224.3	1,719.6	5,701.2	284.9	1,238.8	43,755.3
2.2.6	UNIT 6								
2.2.6.1	Acid, Caustic and Boiler Chemical Feed	57.0		8.5	65.5	45.9	0.5	2.8	1,680.7
2.2.6.2	Boiler Feedwater	363.8		54.6	418.4	2,211.7	145.6	2.5	10,811.1
2.2.6.4	Circulating Water	180.9		27.1	208.0	473.6	0.3	21.8	5,397.4
2.2.6.5	Coal Handling/Supply	168.3		25.3	193.6	618.9	13.3	31.5	4,921.9
2.2.6.6	Combustion Air and Flue Gas	93.8		14.1	107.9	141.5	13.9	0.3	2,635.6
2.2.6.7	Compressed Air	14.2		2.1	16.3	15.6	0.2		421.4
2.2.6.8	Condensate	11.9		1.8	13.7	16.5	0.3	1.5	344.8
2.2.6.9	Condenser Air Removal	59.4		8.9	68.3	379.8	0.3	18.0	1,786.4
2.2.6.10	Diesel/Gas Turbine Generator	2.5		0.4	2.9	14.3		0.7	70.2
2.2.6.11	Drains	29.8		4.5	34.3	146.3	43.8	0.5	858.5
2.2.6.12	Electrical System	259.0		38.8	297.8	1,196.5		1,157.6	7,537.2
2.2.6.13	Equipment Cooling Water	40.0		6.0	46.1	156.0	40.0	2.0	1,158.8
2.2.6.14	Fuel Oil Supply	136.6		20.5	157.1	131.0	13.4	1.0	3,841.8
2.2.6.15	Hydrogen and Carbon Dioxide	0.2		0.0	0.2	0.2			5.2
2.2.6.16	Lubricating Oil	20.4		3.1	23.5	19.7	2.1	0.3	574.8
2.2.6.17	Main Steam, Hot and Cold Reheat	43.2		6.5	49.7	115.3	11.4		1,287.8
2.2.6.18	Seal Water	8.0		1.2	9.2	7.7		0.5	235.2
2.2.6.19	Vents	2.9		0.4	3.3	6.0			86.1
2.2.6.20	Waste Treatment	3.4		0.5	3.9	4.7	0.0	0.0	100.3
2.2.6	UNIT 6 Totals	1,495.3		224.3	1,719.6	5,701.2	284.9	1,238.8	43,755.3
2.2.7	UNIT 7								
2.2.7.1	Acid, Caustic and Boiler Chemical Feed	314.9		47.2	362.2	420.3	1.2	8.4	9,425.6
2.2.7.2	Auxiliary Steam	65.0		9.8	74.8	107.0	5.7	0.1	1,945.7
2.2.7.3	Boiler Feedwater	2,025.5		303.8	2,329.3	17,878.7	217.0	30.0	61,098.1
2.2.7.4	Building Heating	115.8		17.4	133.2	77.5	0.1		3,441.0
2.2.7.5	Circulating Water	135.4		20.3	155.7	117.9	6.8	0.0	3,904.3
2.2.7.6	Coal Handling/Supply	197.8		29.7	227.5	253.4	3.3	0.9	5,833.8
2.2.7.7	Combustion Air and Flue Gas	80.9		12.1	93.0	248.6	16.8		2,273.2
2.2.7.8	Compressed Air	360.7		54.1	414.8	960.4	10.5	12.0	10,615.1
2.2.7.9	Condensate	144.0		21.6	165.6	280.8	25.1	1.5	4,312.8
2.2.7.10	Condenser Air Removal	163.8		24.6	188.4	702.8	0.3	21.0	4,970.8
2.2.7.11	Diesel/Gas Turbine Generator	2.5		0.4	2.9	14.3		0.7	70.2
2.2.7.12	Drains	7.0		1.1	8.1	15.5	0.1	1.5	203.7
2.2.7.13	Electrical System	259.0		38.8	297.8	1,196.5		1,157.6	7,537.2
2.2.7.14	Equipment Cooling Water	234.0		35.1	269.1	618.5	140.0	2.5	6,892.8
2.2.7.15	Extraction Steam	33.4		5.0	38.4	64.7			1,012.1
2.2.7.16	Fire Protection	78.5		11.8	90.3	95.8	0.2	1.5	2,353.7
2.2.7.17	Fuel Oil Supply	279.6		41.9	321.5	266.5	27.3	2.0	7,864.7
2.2.7.18	Hydrogen and Carbon Dioxide	0.2		0.0	0.2	0.2			5.2
2.2.7.19	Lubricating Oil	56.6		8.5	65.0	62.5	1.9	2.5	1,637.4
2.2.7.20	Main Steam, Hot and Cold Reheat	189.3		28.4	217.7	266.2	20.9	20.0	5,605.9
2.2.7.21	Seal Water	27.0		4.0	31.0	16.4	0.2	0.5	798.6
2.2.7.22	Vents	9.3		1.4	10.6	14.1			273.8
2.2.7.23	Waste Treatment	7.5		1.1	8.7	7.7	0.0	0.0	225.5
2.2.7	UNIT 7 Totals	4,787.8		718.2	5,505.9	23,686.3	477.4	1,262.7	142,299.2
2.2	System Removal Station Totals	11,595.5		1,739.3	13,334.9	54,928.6	2,284.5	8,730.2	341,450.6
2.3	**Removal of Main Turbine / Generator**								
2.3.1	Unit 1	17.1		2.6	19.7	456.0			473.5
2.3.2	Unit 2	17.1		2.6	19.7	456.0			473.5

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
2.3.3	Unit 3	17.1		2.6	19.7	456.0			473.5
2.3.4	Unit 4	17.1		2.6	19.7	456.0			473.5
2.3.5	Unit 5	19.9		3.0	22.9	531.3			551.7
2.3.6	Unit 6	19.9		3.0	22.9	531.3			551.7
2.3.7	Unit 7	34.6		5.2	39.8	922.8			958.3
2.3	Station Turbine/Generator Totals	142.8		21.4	164.2	3,809.2			3,955.5
2.4	**Removal of Main Condenser**								
2.4.1	Unit 1	34.0		5.1	39.1	211.8			924.5
2.4.2	Unit 2	34.0		5.1	39.1	211.8			924.5
2.4.3	Unit 3	34.0		5.1	39.1	211.8			924.5
2.4.4	Unit 4	34.0		5.1	39.1	211.8			924.5
2.4.5	Unit 5	36.7		5.5	42.2	228.1			996.6
2.4.6	Unit 6	36.7		5.5	42.2	228.1			996.6
2.4.7	Unit 7	125.7		18.9	144.6	781.8			3,415.0
2.4	Station Condenser Totals	335.2		50.3	385.5	2,084.6			9,108.2
2.5	**Demolition of Remaining Site Buildings**								
2.5.1	Boiler/Turbine Building (Unit 7)	3,317.8		497.7	3,815.4	4,796.9			79,077.6
2.5.2	Boiler/Turbine Building (Units 1-6)	5,326.8		799.0	6,125.8	5,613.4			122,931.1
2.5.3	Coal Handling Buildings/Structures	471.5		70.7	542.3	654.7			10,728.5
2.5.4	Cooling Tower Structures	579.2		86.9	666.1				14,487.2
2.5.5	Crib House/Intake Buildings & Structures	77.0		11.5	88.5	101.9			1,726.5
2.5.6	Other Buildings & Structures	135.7		20.4	156.0	146.2			2,538.0
2.5.7	Stack/Precipitator Structures	577.5		86.6	664.1	1,092.9			13,963.8
2.5	Station Building Demolition Totals	10,485.4		1,572.8	12,058.3	12,405.9			245,452.7
2.6	**Period 2 Undistributed Costs**								
2.6.1	Insurance		302.8	30.3	333.1				
2.6.2	Heavy equipment rental		2,970.8	445.6	3,416.4				
2.6.3	Pipe cutting equipment		587.2	88.1	675.3				
2.6.4	Small Tool Allowance	171.4		25.7	197.1				
2.6	Subtotal Undistributed Costs Period 2	171.4	3,860.8	589.7	4,622.0				
2.7	**Period 2 Staff Costs**								
2.7.1	DOC Staff Cost		2,762.4	414.4	3,176.7				
2.7.2	Utility Staff Cost		2,699.0	404.9	3,103.9				
2.7	Subtotal Staff Costs Period 2		5,461.4	819.2	6,280.6				
2	**TOTAL PERIOD 2**	**25,671.9**	**9,372.6**	**5,540.7**	**40,585.3**	**73,228.3**	**2,284.5**	**8,730.2**	**708,136.5**
Period 2 Costs Breakdown by Unit									
	Unit 1	**1,996.5**	**449.6**	**400.5**	**2,846.6**	**6,313.8**	**309.3**	**1,247.5**	**57,237.5**
	Unit 2	**1,996.5**	**449.6**	**400.5**	**2,846.6**	**6,313.8**	**309.3**	**1,247.5**	**57,237.5**
	Unit 3	**2,299.3**	**458.1**	**476.1**	**3,233.5**	**6,327.8**	**309.3**	**1,247.5**	**68,727.5**
	Unit 4	**2,299.3**	**458.1**	**476.1**	**3,233.5**	**6,327.8**	**309.3**	**1,247.5**	**68,727.5**
	Unit 5	**3,914.5**	**1,204.3**	**824.0**	**5,942.8**	**8,327.9**	**284.9**	**1,238.8**	**102,918.2**
	Unit 6	**3,772.7**	**1,204.3**	**788.6**	**5,765.6**	**8,327.9**	**284.9**	**1,238.8**	**102,918.2**
	Unit 7	**9,393.1**	**5,148.6**	**2,174.9**	**16,716.7**	**31,289.3**	**477.4**	**1,262.7**	**250,370.1**
Period 2 Station Totals		25,671.9	9,372.6	5,540.7	40,585.3	73,228.3	2,284.5	8,730.2	708,136.5
3	**PERIOD 3**								
3.1	Site Closeout Activities								
3.1.1	BackFill Site	333.4		50.0	383.4				1,828.4
3.1.2	Grade and Landscape Site	5,789.4		868.4	6,657.8				3,123.6
3.1	Station Closeout Totals	6,122.8		918.4	7,041.2				4,952.0
3.2	Period 3 Undistributed Costs								
3.2.1	Insurance		10.8	1.1	11.9				
3.2.2	Heavy equipment rental		80.3	12.0	92.4				
3.2.4	Small Tool Allowance	22.2		3.3	25.5				
3.2	Subtotal Undistributed Costs Period 3	22.2	91.1	16.4	129.7				
3.3	Staff Costs Period 3								
3.3.1	DOC Staff Cost		102.1	15.3	117.4				

Indianapolis Power & Light Co.
Dismantling Cost Estimate

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
3.3.2	Utility Staff Cost		31.9	4.8	36.7				
3.3	Subtotal Staff Costs Period 3		134.0	20.1	154.1				
TOTAL PERIOD 3		6,145.0	225.1	956.0	7,325.0				4,952.0
Period 3 Costs Breakdown by Unit									
	Unit 1	290.3	10.6	45.1	346.1				707.4
	Unit 2	290.3	10.6	45.1	346.1				707.4
	Unit 3	296.2	10.9	46.0	353.1				707.4
	Unit 4	296.2	10.9	46.0	353.1				707.4
	Unit 5	790.0	28.9	122.8	941.7				707.4
	Unit 6	790.0	28.9	122.8	941.7				707.4
	Unit 7	3,391.8	124.2	527.1	4,043.2				707.4
Period 3 Station Totals		6,145.0	225.1	956.0	7,325.0				4,952.0
TOTAL COST TO DISMANTLE		31,816.9	11,427.5	6,763.8	50,008.3	73,228.3	2,284.6	8,730.2	713,088.5

Total Expenditures to Dismantle with 15.64% Contingency:				$50,008,270
1993 Dollars				
Credit for Scrap Metal Removed:				
Carbon Steel Scrap Tonnage	73,228	@$100.00 / ton	$7,322,834	
Stainless Steel Scrap Tonnage	2,285	@$240.00 / ton	$548,285	
Copper Scrap Tonnage	8,730	@$1100.00 / ton	$9,603,248	
Total Scrap Metal Credit	84,243.1	Tons		($17,474,367)
Estimated Adjusted Cost to Utility to Dismantle:				$32,533,903
TOTAL CRAFT LABOR REQUIREMENTS:				713,088.5 MAN-HOURS

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
TOTAL COST TO DISMANTLE BREAKDOWN BY UNIT									
	Unit 1	2,286.8	546.7	458.3	3,291.8	6,313.8	309.3	1,247.5	57,945.0
	Unit 2	2,286.8	546.7	458.3	3,291.8	6,313.8	309.3	1,247.5	57,945.0
	Unit 3	2,595.6	557.1	535.1	3,687.8	6,327.8	309.3	1,247.5	69,434.9
	Unit 4	2,595.6	557.1	535.1	3,687.8	6,327.8	309.3	1,247.5	69,434.9
	Unit 5	4,704.4	1,468.6	981.2	7,154.2	8,327.9	284.9	1,238.8	103,625.6
	Unit 6	4,562.7	1,468.5	945.8	6,977.0	8,327.9	284.9	1,238.8	103,625.6
	Unit 7	12,785.0	6,282.9	2,850.0	21,917.8	31,289.3	477.4	1,262.7	251,077.6
Total Cost for All Units		31,616.9	11,427.5	6,763.8	50,008.3	73,226.3	2,284.6	8,730.2	713,088.5

UNIT BREAKDOWN (1993 Dollars)	UNIT 1		UNIT 2		UNIT 3		UNIT 4	
Total Expenditures to Dismantle by Unit		$3,291,798		$3,291,798		$3,687,809		$3,687,809
Contingency		16.16%		16.16%		16.97%		16.97%
Credit for Scrap Metal Removed:								
Carbon steel scrap @ $100.00 / ton	6,314	$631,381	6,314	$631,381	6,328	$632,782	6,328	$632,782
Stainless steel scrap @ $240.00 / ton	309	$74,237	309	$74,237	309	$74,237	309	$74,237
Copper scrap @ $1100.00 / ton	1,247	$1,372,214	1,247	$1,372,214	1,247	$1,372,214	1,247	$1,372,214
Total Scrap Metal Credit	7,870.6	($2,077,832)	7,870.6	($2,077,832)	7,884.6	($2,079,233)	7,884.6	($2,079,233)
Estimated Adjusted Cost to Utility to Dismantle:		$1,213,966		$1,213,966		$1,608,576		$1,608,576
TOTAL CRAFT LABOR REQUIREMENTS		57,945.0		57,945.0		69,434.9		69,434.9

UNIT BREAKDOWN (1993 Dollars)	UNIT 5		UNIT 6		UNIT 7	
Total Expenditures to Dismantle by Unit		$7,154,172		$6,977,042		$21,917,843
Contingency		15.90%		15.68%		14.95%
Credit for Scrap Metal Removed:						
Carbon steel scrap @ $100.00 / ton	8,328	$832,790	8,328	$832,790	31,289	$3,128,928
Stainless steel scrap @ $240.00 / ton	285	$68,384	285	$68,384	477	$114,570
Copper scrap @ $1100.00 / ton	1,239	$1,362,710	1,239	$1,362,710	1,263	$1,388,970
Total Scrap Metal Credit	9,851.7	($2,263,884)	9,851.7	($2,263,884)	33,029.4	($4,632,469)
Estimated Adjusted Cost to Utility to Dismantle:		$4,890,288		$4,713,158		$17,285,374
TOTAL CRAFT LABOR REQUIREMENTS		103,625.6		103,625.6		251,077.6

APPENDIX H

PETERSBURG GENERATING STATION
DETAILED COST TABLES

FOSSIL STATION DISMANTLING ESTIMATE

Petersburg Generating Station
Indianapolis Power and Light Company
Wednesday, February 23, 1994

Costs stated in thousands of 1993 dollars unless otherwise noted.
Columns may not total due to rounding.
Identical values may indicate cost sharing with other units.
93.12.28 DECCER Version
20:55:27 TIME OF RUN

Scrap Value:

Copper	$1,100.00	per ton
Stainless Steel	$240.00	per ton
Carbon Steel	$100.00	per ton

TABLE 1
Petersburg Generating Station Dismantling Cost Summary
1993 Dollars

Dismantling Activity Cost	$50,210,288
Period - Dependent Cost	$22,211,215
Subtotal	$72,421,503
Contingency	$11,020,095
Cost Subtotal	$83,441,599
Scrap Credit	($19,833,992)
Total Project Cost	$63,607,606

TABLE 3
Petersburg Generating Station Accounts Summary
Thousands of 1993 Dollars

Plant Type	Plant Dismantling Cost	Period Dependent Cost	Scrap Credit	Total
Steam Plant	$57,980	$25,440	($19,822)	$63,597
Diesel-Generators	$15	$7	($12)	$10
Totals Across Plant Types	$57,995	$25,447	($19,834)	$63,608

TABLE 2
Petersburg Generating Station Dismantling Activity Cost Summary
Thousands of 1993 Dollars

Activity	Costs	Percent
Asbestos Abatement	$3,164	3.79%
Systems Removal	$20,044	24.02%
Structures Demolition	$21,797	26.12%
Site Restoration	$11,978	14.36%
Utility Staffing	$7,744	9.28%
DOC Staffing	$8,006	9.59%
Liability Insurance	$2,117	2.54%
Tools & Equipment	$8,592	10.30%
Total Dismantling Costs	$83,442	100.00%
Scrap Credit	($19,834)	
Total Project Cost	$63,608	

TABLE 4
Petersburg Generating Station Scrap Value by Plant Type
1993 Dollars

Plant Type	Carbon Stl (tons)	Stainless Stl (tons)	Copper (tons)	Value
Steam Plant	108,662.99	1,763.90	7,757.03	$19,822,367
Diesel-Generators	75.00		3.75	$11,625
Totals	108,737.99	1,763.90	7,760.78	$19,833,992

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
1	PERIOD 1								
1.1	Period 1 Undistributed Costs								
1.1.1	Insurance		304.9	30.5	335.4				
1.1	Subtotal Undistributed Costs Period 1		304.9	30.5	335.4				
1.2	Period 1 Staff Costs								
1.2.1	DOC Staff Cost		824.9	123.7	948.6				
1.2.2	Utility Staff Cost		876.8	131.5	1,008.3				
1.2	Subtotal Staff Costs Period 1		1,701.7	255.3	1,956.9				
1	**TOTAL PERIOD 1 COST**		**2,006.6**	**285.7**	**2,292.3**				
Period 1 Costs Breakdown by Unit									
	Unit 1		**258.0**	**36.7**	**294.7**				
	Unit 2		**503.1**	**71.6**	**574.8**				
	Unit 3		**622.7**	**88.7**	**711.4**				
	Unit 4		**622.7**	**88.7**	**711.4**				
Period 1 Station Totals			2,006.6	285.7	2,292.3				
2	PERIOD 2								
2.1	**Asbestos Abatement**								
2.1.1	Unit 1	1,512.7	31.0	385.9	1,929.6				
2.1.2	Unit 2	751.9	23.2	193.8	968.9				
2.1.3	Unit 3	89.5	16.5	26.5	132.5				
2.1.4	Unit 4	89.5	16.5	26.5	132.5				
2.1	Station Total	2,443.7	87.2	632.7	3,163.6				
2.2	**Removal of Plant Systems**								
2.2.1	UNIT 1								
2.2.1.1	Acid, Caustic and Boiler Chemical Feed	173.8		26.1	199.9	272.7	0.8	7.8	5,186.4
2.2.1.2	Boiler Feedwater	631.9		94.8	726.7	1,787.7	125.1	25.0	20,075.3
2.2.1.3	Circulating Water	32.8		4.9	37.8	23.6	0.0	0.0	972.6
2.2.1.4	Coal Handling/Supply	177.9		26.7	204.6	600.1	12.6		5,073.9
2.2.1.5	Combustion Air and Flue Gas	78.7		11.8	90.5	182.7	17.0		2,210.8
2.2.1.6	Compressed Air	141.8		21.3	163.1	234.5		11.5	4,188.2
2.2.1.7	Condensate	154.8		23.2	178.0	448.4	34.7	10.1	4,614.8
2.2.1.8	Condenser Air Removal	95.1		14.3	109.4	499.8	0.3	16.0	2,871.2
2.2.1.9	Diesel/Gas Turbine Generator	3.3		0.5	3.8	18.8		0.9	92.3
2.2.1.10	Drains	4.4		0.7	5.1	10.0		1.0	127.9
2.2.1.11	Electrical System	997.3		149.6	1,146.9	1,782.0		1,838.8	29,111.7
2.2.1.12	Equipment Cooling Water	89.3		13.4	102.7	287.2	63.8	2.0	2,617.0
2.2.1.13	Fuel Oil Supply	12.5		1.9	14.3	20.4	0.6	1.5	356.5
2.2.1.14	Hydrogen and Carbon Dioxide	0.3		0.1	0.4	0.5		0.1	10.4
2.2.1.15	Lubricating Oil	28.6		4.3	32.9	39.7	0.5	2.0	832.5
2.2.1.16	Main Steam, Hot and Cold Reheat	58.1		8.7	66.8	114.6	10.5	10.0	1,715.7
2.2.1.17	Miscellaneous Plant Systems	4.8		0.7	5.5	21.3			136.2
2.2.1.18	Seal Water	90.3		13.5	103.9	212.2	1.3	7.8	2,663.4
2.2.1.19	Vents	9.5		1.4	10.9	14.4			280.1
2.2.1	Unit 1 Totals	2,785.3		417.8	3,203.1	6,570.6	267.1	1,934.5	83,136.8
2.2.2	UNIT 2								
2.2.2.1	Acid, Caustic and Boiler Chemical Feed	281.4		42.2	323.6	390.3	1.0	7.9	8,412.2
2.2.2.2	Boiler Feedwater	2,030.2		304.5	2,334.7	17,867.8	217.0	30.0	61,305.9
2.2.2.3	Circulating Water	68.3		10.2	78.6	49.3	1.2	0.0	2,006.2
2.2.2.4	Coal Handling/Supply	230.1		34.5	264.6	624.8	12.6		6,619.6
2.2.2.5	Combustion Air and Flue Gas	70.9		10.6	81.5	239.4	15.8		1,992.0
2.2.2.6	Compressed Air	277.4		41.6	319.0	332.1		12.0	8,208.9
2.2.2.7	Condensate	197.5		29.6	227.1	499.8	34.9	10.0	5,906.8

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
2.2.2.8	Condenser Air Removal	155.2		23.3	178.5	681.7	0.3	21.0	4,702.8
2.2.2.9	Diesel/Gas Turbine Generator	3.3		0.5	3.8	18.8		0.9	92.3
2.2.2.10	Drains	6.6		1.0	7.6	15.0		1.5	191.8
2.2.2.11	Electrical System	994.0		149.1	1,143.1	1,763.2		1,837.9	29,019.4
2.2.2.12	Equipment Cooling Water	172.8		25.9	198.8	592.8	143.8	2.5	5,072.9
2.2.2.13	Fuel Oil Supply	17.1		2.6	19.6	26.6	0.6	2.0	491.6
2.2.2.14	Hydrogen and Carbon Dioxide	2.5		0.4	2.9	7.0		0.3	71.2
2.2.2.15	Lubricating Oil	39.8		6.0	45.8	49.8	0.5	2.5	1,162.0
2.2.2.16	Main Steam, Hot and Cold Reheat	121.6		18.2	139.8	231.3	20.9	20.0	3,590.5
2.2.2.17	Miscellaneous Plant Systems	4.8		0.7	5.5	21.3			136.2
2.2.2.18	Seal Water	139.6		20.9	160.6	265.0	1.3	9.3	4,130.0
2.2.2.19	Vents	11.8		1.8	13.6	17.0			349.5
2.2.2	Unit 2 Totals	4,890.8		733.6	5,624.4	23,801.9	455.6	1,957.9	145,432.1
2.2.3	UNIT 3								
2.2.3.1	Acid, Caustic and Boiler Chemical Feed	80.5		12.1	92.6	78.0	1.1	0.4	2,374.4
2.2.3.2	Auxiliary Steam	53.9		8.1	62.0	108.5	0.7	0.3	1,633.2
2.2.3.3	Boiler Feedwater	1,298.2		194.7	1,492.9	16,436.6	242.0	15.9	40,273.2
2.2.3.4	Circulating Water	136.7		20.5	157.2	475.3		11.5	4,131.1
2.2.3.5	Coal Handling/Supply	402.0		60.3	462.4	1,038.2	18.9		11,678.9
2.2.3.6	Combustion Air and Flue Gas	4.0		0.6	4.6	4.9			114.2
2.2.3.7	Compressed Air	2.4		0.4	2.8	4.8	0.2		70.9
2.2.3.8	Condensate	230.3		34.5	264.8	561.6	34.9	15.0	6,869.4
2.2.3.9	Condenser Air Removal	141.6		21.2	162.9	648.6	0.3	21.0	4,283.8
2.2.3.10	Diesel/Gas Turbine Generator	3.3		0.5	3.8	18.8		0.9	92.3
2.2.3.11	Drains	90.1		13.5	103.6	81.3			2,684.6
2.2.3.12	Electrical System	994.0		149.1	1,143.1	1,763.2		1,837.9	29,019.4
2.2.3.13	Equipment Cooling Water	335.5		50.3	385.8	895.0	187.8	10.0	9,871.6
2.2.3.14	Extraction Steam	92.2		13.8	106.0	166.5		10.0	2,764.8
2.2.3.15	Fuel Oil Supply	90.4		13.6	103.9	91.7	8.5	1.5	2,545.0
2.2.3.16	Hydrogen and Carbon Dioxide	0.3		0.1	0.4	0.5		0.1	10.4
2.2.3.17	Lubricating Oil	53.7		8.0	61.7	43.9	0.6	0.5	1,574.2
2.2.3.18	Main Steam, Hot and Cold Reheat	327.3		49.1	376.4	384.0	21.0		9,709.3
2.2.3.19	Miscellaneous Plant Systems	4.8		0.7	5.5	21.3			136.2
2.2.3.20	Seal Water	196.0		29.4	225.3	308.5	4.6	9.3	5,742.3
2.2.3.21	Vents	15.9		2.4	18.3	21.5			470.4
2.2.3	Unit 3 Totals	4,553.1		683.0	5,236.1	23,152.6	520.6	1,934.2	136,049.4
2.2.4	UNIT 4								
2.2.4.1	Acid, Caustic and Boiler Chemical Feed	80.5		12.1	92.6	78.0	1.1	0.4	2,374.4
2.2.4.2	Auxiliary Steam	53.9		8.1	62.0	108.5	0.7	0.3	1,633.2
2.2.4.3	Boiler Feedwater	1,298.2		194.7	1,492.9	16,436.6	242.0	15.9	40,273.2
2.2.4.4	Circulating Water	136.7		20.5	157.2	475.3		11.5	4,131.1
2.2.4.5	Coal Handling/Supply	402.0		60.3	462.4	1,038.2	18.9		11,678.9
2.2.4.6	Combustion Air and Flue Gas	4.0		0.6	4.6	4.9			114.2
2.2.4.7	Compressed Air	2.4		0.4	2.8	4.8	0.2		70.9
2.2.4.8	Condensate	230.3		34.5	264.8	561.6	34.9	15.0	6,869.4
2.2.4.9	Condenser Air Removal	141.6		21.2	162.9	648.6	0.3	21.0	4,283.8
2.2.4.10	Diesel/Gas Turbine Generator	3.3		0.5	3.8	18.8		0.9	92.3
2.2.4.11	Drains	90.1		13.5	103.6	81.3			2,684.6
2.2.4.12	Electrical System	994.0		149.1	1,143.1	1,763.2		1,837.9	29,019.4
2.2.4.13	Equipment Cooling Water	335.5		50.3	385.8	895.0	187.8	10.0	9,871.6
2.2.4.14	Extraction Steam	92.2		13.8	106.0	166.5		10.0	2,764.8
2.2.4.15	Fuel Oil Supply	90.4		13.6	103.9	91.7	8.5	1.5	2,545.0
2.2.4.16	Hydrogen and Carbon Dioxide	0.3		0.1	0.4	0.5		0.1	10.4
2.2.4.17	Lubricating Oil	53.7		8.0	61.7	43.9	0.6	0.5	1,574.2
2.2.4.18	Main Steam, Hot and Cold Reheat	327.3		49.1	376.4	384.0	21.0		9,709.3
2.2.4.19	Miscellaneous Plant Systems	4.8		0.7	5.5	21.3			136.2
2.2.4.20	Seal Water	196.0		29.4	225.3	308.5	4.6	9.3	5,742.3
2.2.4.21	Vents	15.9		2.4	18.3	21.5			470.4
2.2.4	UNIT 4 Totals	4,553.1		683.0	5,236.1	23,152.6	520.6	1,934.2	136,049.4
2.2	System Removal Station Totals	16,782.3		2,517.3	19,299.6	76,677.7	1,763.9	7,760.8	500,667.8

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
2.3	**Removal of Main Turbine / Generator**								
2.3.1	Unit 1	25.3		3.8	29.1	674.1			700.0
2.3.2	Unit 2	34.6		5.2	39.8	923.6			959.1
2.3.3	Unit 3	39.2		5.9	45.0	1,044.8			1,085.0
2.3.4	Unit 4	39.2		5.9	45.0	1,044.8			1,085.0
2.3	Station Turbine/Generator Totals	138.2		20.7	159.0	3,687.4			3,829.0
2.4	**Removal of Main Condenser**								
2.4.1	Unit 1	78.9		11.8	90.7	490.4			2,142.1
2.4.2	Unit 2	115.4		17.3	132.7	717.8			3,135.6
2.4.3	Unit 3	160.0		24.0	184.0	995.0			4,346.3
2.4.4	Unit 4	154.4		23.2	177.5	959.9			4,193.0
2.4	Station Condenser Totals	508.6		76.3	584.9	3,163.0			13,817.0
2.5	**Demolition of Remaining Site Buildings**								
2.5.1	Boiler/Turbine Building (Units 1-4)	13,078.1		1,961.7	15,039.8	21,240.2			313,738.6
2.5.2	Coal Handling Buildings/Structures	1,033.4		155.0	1,188.4	1,736.2			24,605.8
2.5.3	Cooling Tower Structures	1,798.1		269.7	2,067.8	21.6			47,224.5
2.5.4	Crib House/Intake Buildings & Structures	768.2		115.2	883.4	180.8			16,111.6
2.5.5	Maintenance Building	9.6		1.4	11.0	20.0			240.0
2.5.6	Other Buildings & Structures	1,088.1		163.2	1,251.3	1,311.7			20,457.5
2.5.7	Stack/Precipitator Structures	1,178.6		176.8	1,355.4	699.4			25,373.1
2.5	Station Building Demolition Totals	18,954.0		2,843.1	21,797.1	25,209.8			447,751.1
2.6	**Period 2 Undistributed Costs**								
2.6.1	Insurance		1,598.1	159.8	1,757.9				
2.6.2	Heavy equipment rental		6,562.1	984.3	7,546.4				
2.6.3	Pipe cutting equipment		587.2	88.1	675.3				
2.6.4	Small Tool Allowance	256.6		38.5	295.1				
2.6	Subtotal Undistributed Costs Period 2	256.6	8,747.4	1,270.7	10,274.7				
2.7	**Period 2 Staff Costs**								
2.7.1	DOC Staff Cost		6,100.1	915.0	7,015.1				
2.7.2	Utility Staff Cost		5,845.8	876.9	6,722.6				
2.7	Subtotal Staff Costs Period 2		11,945.9	1,791.9	13,737.7				
2	**TOTAL PERIOD 2**	**39,083.4**	**20,780.4**	**9,152.8**	**69,016.5**	**108,736.0**	**1,763.9**	**7,760.8**	**966,064.9**
Period 2 Costs Breakdown by Unit									
	Unit 1	**8,871.9**	**2,691.4**	**1,578.6**	**11,142.0**	**10,976.2**	**267.1**	**1,934.5**	**143,544.9**
	Unit 2	**10,609.7**	**5,212.0**	**2,430.7**	**18,252.4**	**31,764.8**	**455.6**	**1,957.9**	**261,798.2**
	Unit 3	**10,803.7**	**6,438.5**	**2,572.1**	**19,814.4**	**33,016.1**	**520.6**	**1,934.2**	**280,437.6**
	Unit 4	**10,798.1**	**6,438.5**	**2,571.3**	**19,807.9**	**32,981.0**	**520.6**	**1,934.2**	**280,284.2**
Period 2 Station Totals		39,083.4	20,780.4	9,152.8	69,016.5	108,738.0	1,763.9	7,760.8	966,064.9
3	PERIOD 3								
3.1	Site Closeout Activities								
3.1.1	BackFill Site	1,005.5		150.8	1,156.3				5,514.2
3.1.2	Site Restoration	9,410.4		1,411.6	10,821.9				663.0
3.1	Station Closeout Totals	10,415.8		1,562.4	11,978.2				6,177.2
3.2	Period 3 Undistributed Costs								
3.2.1	Insurance		21.3	2.1	23.5				
3.2.2	Heavy equipment rental		29.0	4.3	33.3				
3.2.4	Small Tool Allowance	36.7		5.5	42.2				
3.2	Subtotal Undistributed Costs Period 3	36.7	50.3	12.0	98.9				
3.3	Staff Costs Period 3								

Activity Number	Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
3.3.1	DOC Staff Cost		36.9	5.5	42.4				
3.3.2	Utility Staff Cost		11.5	1.7	13.2				
3.3	Subtotal Staff Costs Period 3		48.4	7.3	55.6				
TOTAL PERIOD 3		**10,452.5**	**98.6**	**1,581.6**	**12,132.7**				**6,177.2**
Period 3 Costs Breakdown by Unit									
	Unit 1	**1,343.8**	**12.7**	**203.3**	**1,559.9**				**794.2**
	Unit 2	**2,620.9**	**24.7**	**396.6**	**3,042.2**				**1,548.9**
	Unit 3	**3,243.9**	**30.6**	**490.8**	**3,765.3**				**1,917.1**
	Unit 4	**3,243.9**	**30.6**	**490.8**	**3,765.3**				**1,917.1**
Period 3 Station Totals		**10,452.5**	**98.6**	**1,581.6**	**12,132.7**				**6,177.2**
TOTAL COST TO DISMANTLE		**49,535.9**	**22,885.6**	**11,020.1**	**83,441.6**	**108,738.0**	**1,763.9**	**7,760.8**	**972,242.1**

Total Expenditures to Dismantle with 15.22% Contingency:				$83,441,591
1993 Dollars				
Credit for Scrap Metal Removed:				
Carbon Steel Scrap Tonnage	108,738	@$100.00 / ton	$10,873,799	
Stainless Steel Scrap Tonnage	1,764	@$240.00 / ton	$423,337	
Copper Scrap Tonnage	7,761	@$1100.00 / ton	$8,536,857	
Total Scrap Metal Credit	118,262.7	Tons		($19,833,992)
Estimated Adjusted Cost to Utility to Dismantle:				$63,607,598
TOTAL CRAFT LABOR REQUIREMENTS:				972,242.1 MAN-HOURS

Activity Number / Activity Description	Removal $	Other $	Contingency $	Total $	C Steel Tons	St Steel Tons	Copper Tons	Craft Hours
TOTAL COST TO DISMANTLE BREAKDOWN BY UNIT								
Unit 1	8,215.8	2,962.1	1,818.7	12,996.5	10,976.2	267.1	1,934.5	144,339.1
Unit 2	13,230.6	5,739.8	2,899.0	21,869.4	31,764.6	455.6	1,957.9	263,347.1
Unit 3	14,047.6	7,091.9	3,151.7	24,291.1	33,016.1	520.6	1,934.2	282,354.7
Unit 4	14,041.9	7,091.9	3,150.8	24,284.6	32,981.0	520.6	1,934.2	282,201.3
Total Cost for All Units	49,535.9	22,885.6	11,020.1	83,441.6	108,738.0	1,763.9	7,760.8	972,242.1

UNIT BREAKDOWN (1993 Dollars)	UNIT 1		UNIT 2		UNIT 3		UNIT 4	
Total Expenditures to Dismantle by Unit		$12,996,536		$21,869,363		$24,291,092		$24,284,600
Contingency		16.27%		15.28%		14.91%		14.91%
Credit for Scrap Metal Removed:								
Carbon steel scrap @ $100.00 / ton	10,976	$1,097,623	31,765	$3,176,458	33,016	$3,301,614	32,981	$3,298,103
Stainless steel scrap @ $240.00 / ton	267	$64,106	456	$109,334	521	$124,948	521	$124,948
Copper scrap @ $1100.00 / ton	1,934	$2,127,928	1,958	$2,153,677	1,934	$2,127,626	1,934	$2,127,626
Total Scrap Metal Credit	13,177.8	($3,289,658)	34,178.0	($5,439,469)	35,471.0	($5,554,189)	35,435.9	($5,550,678)
Estimated Adjusted Cost to Utility to Dismantle:		$9,706,878		$16,429,894		$18,736,904		$18,733,922
TOTAL CRAFT LABOR REQUIREMENTS		144,339.1		263,347.1		282,354.7		282,201.3

APPENDIX I

DESCRIPTION OF SCHEDULE TASKS LISTED IN FIGURES 4.1, 4.2 AND 4.3

APPENDIX I

DESCRIPTION OF SCHEDULE TASKS LISTED IN FIGURES 4.1, 4.2 AND 4.3

PROJ.START	Initiate Project
SELECT STAFF	Select IP&L Administrative & Engineering Staffs
ST PERIOD1 A	Start Period 1A (IP&L Preliminary Planning and Preparation)
PRE-PLAN	Start Planning & Preparations For Site Shutdown
INCINRT OIL	Incinerate Any Oil Surplus
CONTRACT DOC	Select Demolition Operations Contractor (DOC)
REMOVE GAS	Remove Any Surplus Gasses From The Site
DRAIN THKNER	Drain Slurry Thickeners
PREP PERMIT1	Prepare Application For Environmental Permits
INCINRT COAL	Incinerate All Existing Coal Stockpiles
INST ENV MON	Install Environmental Monitors
RMV MISC STR	Remove All Temporary Structures And Personal Property Not Needed During Dismantling
BEGIN PREP	Begin Site Preparations
DRY COAL SIL	De-Water Coal Silo
APPL PERMIT1	Submit Application For Environmental Permits
RECV PERMIT1	Receive Environmental Permits
RMV ASH/SLUR	Remove Ash And Slurry From Systems And Structures
RMV LIME RES	Remove Any Limestone Surplus
EMPTY ACIDS	Empty All Acid And Caustic Surplus On Site
RVW SYS DATA	Review System Drawings & Data
DRY ASH POND	De-Water Ash Ponds & Lagoons
RVW STR DATA	Review Site Structural Data
END PERIOD1A	End Period 1A (IP&L Preliminary Planning & Preparation)
PR-CLOSR MON	Perform Pre-Closure Monitoring
ST PERIOD1 B	Start Period 1B (DOC Engineering and Planning)
END PREP	End Preliminary Planning & Preparations
FNL INVNTORY	Finalize Plant Inventory For Dismantling
PREP PERMIT2	Prepare Permit Application For Demolition/Dismantling
RMV ASBESTOS	IP&L Subcontract and Mobilize for Asbestos Removal
ACTIV SPECS	Prepare Activity Specification
SAFETY ANAL	Prepare Safety Analysis Of Cutting Fluids/Dismantling Plans

APPENDIX I

DESCRIPTION OF SCHEDULE TASKS LISTED IN FIGURES 4.1, 4.2 AND 4.3 (Continued)

PREP WRK FRM	Prepare Work Forms
DVL DISM PLN	Develop Dismantling Plan
DETAIL PROCD	Prepare Detail Procedures
SUBMIT PLAN	Submit Dismantling Plan To IP&L
REC'V AUTHOR	Receive Dismantling Plan Approval From IP&L
APPL PERMIT2	Submit Permit Application For Demolition/Dismantling
RECV PERMIT2	Receive Permit For Demolition/Dismantling
STRT PERIOD2	Begin Period 2 (i.e. Dismantling)
END PERIOD 1B	End Period 1B (DOC Engineering & Planning)
MOBILIZE DOC	Mobilize DOC Staff
MOB LABOR	Mobilize Labor Force
MOB EQUIP	Procure Equipment
MOB TEMP SER	Mobilize Temporary Services
RMV COAL HND	Demolish Coal Handling Facility
RMV MISC EQP	Remove All Miscellaneous Equipment
FILL VOIDS	Fill All Voids With Non-Hazardous Structural Materials
EXC WTR LINE	Excavate & Collapse Circulating Water Lines
RMV TURB/GEN	Remove Turbine/Generator
RMV AUX EQUI	Remove Auxiliary Power Equipment
RMV INTAKE	Remove Intake Systems & Cooling Towers
RMV NONESS B	Remove All Non-Essential Systems 'B'
END MOBILIZE	End Mobilization
RMV NONESS A	Remove All Non-Essential Systems 'A'
RMV BOILERS	Cut Top Platens/Waterwalls/Headers/Sides/Buckstays
RMV ESSEN C	Remove All Essential Systems 'C'
RMV OTHR BLD	Demolish All Other Buildings & Structures
RMV MNTN BLG	Demolish Maintenance Building
RMV CRIB HSE	Demolish Crib House
RMV COOL TWR	Demolish Cooling Towers
RMV BLR BLDS	Demolish Boiler Buildings
RMV PRECIP	Dismantle Electrostatic Precipitator
RMV PEDISTAL	Demolish Turbine/Generator Pedestal
BLAST STACK	Demolish Main Stack
BLAST MATS	Demolish And Perforate Existing Mat Foundations

APPENDIX I

DESCRIPTION OF SCHEDULE TASKS LISTED IN FIGURES 4.1, 4.2 AND 4.3 (Continued)

RELOC RAILS	Relocate Railroad Spurs
STRT PERIOD3	Begin Period 3 (i.e. Site Restoration)
SITE RESTORE	Restore Property Per Environmental And IP&L Regulations
END PERIOD 2	End Period 2 (i.e. Dismantling)
BEGIN DEMOB	Begin Demobilization
DEMOB DOC	Demobilize DOC Staff
DEMOB EQUIP	Demobilize Equipment
END PR-CL MN	End Pre-Closure Environmental Monitoring
DEMOB TEMPOR	Demobilize Any Temporary Services
DEMOB LABOR	Demobilize Labor Force
END PERIOD 3	End Of Period 3 (i.e. Site Restoration)
PROJECT END	End Of Project
POST-CLSR MN	Perform 30-Year Post-Closure Environmental Monitoring
END DEMOB	End Demobilization

Exhibit TSL-2

Prompt dismantling Alternative-Extended Surveillance and Maintenance Cost Estimate

Security Guards:
2 per shift (one at guardhouse, one on patrol)
Five shifts per week (24 hours per day, seven days per week, plus relief - holidays/vacations/training)
Fully burdened rate $21.76 per hour (from IPL)
10 guards x 2080 hours/year x $21.76/hour = $452,600/year

Security Equipment:

Guard vehicles - one every three years	= $5,000/year
Intrusion detection equipment allowance	= $1,000/year
Gasoline and maintenance	= $5,000/year

Building and Grounds Maintenance:
Building roof replacement (every 15 years):

Stout	190,123 sq ft
Pritchard	51,596 sq ft
Petersburg	335,542 sq ft
Average	192,420 sq ft

Roof Cost	$1.36/sq ft (R.S. Means, "Building Construction Cost Data 1993," Section 075-100)

192,420 sq ft x $1.36/sq ft x 1/15 years = $17,400/year

Building painting (every 10 years):

Stout	317,753 sq ft
Pritchard	35,208 sq ft
Petersburg	753,188 sq ft
Average	368,716 sq ft

Painting cost $0.27/sq ft(R.S. Means, "Building Construction Cost Data 1993," Section 099-100)

368,716 sq ft x $0.27/sq ft x 1/10 years = $10,000/year

Grounds maintenance:

Snow removal, grass cutting, etc. - allowance = $5,000/year

Electricity:

Heating, cooling of guardhouse, lighting of structures - allowance = $5,000/year

Telephone:

Security telephone service - allowance = $1,000/year

Liability Insurance estimate = $20,000/year

Miscellaneous:
Allowance = $1,000/year

These costs total $523,000/year.

For the purpose of this calculation, assume the period to be 1,000 years. The total cost would be $523.0 million per power plant. This is greater than any of the prompt dismantling cost estimates.

If the period were only 100 years, the cost would be $52.30 million which is greater than the dismantling costs for Pritchard and Stout and almost as great as the cost for dismantling Petersburg. After 100 years, the plants would still have to be dismantled at additional cost. Clearly, indefinite maintenance and security is not cost effective.

PETITIONER'S EXHIBIT DSR
I.U.R.C. Cause No. 39938

INDIANAPOLIS POWER & LIGHT COMPANY
1994 ELECTRIC RATE CASE

DONALD S. ROFF
SENIOR MANAGER
DELOITTE & TOUCHE LLP

DIRECT TESTIMONY
ON
DEPRECIATION

SPONSORING
PETITIONER'S EXHIBITS DSR -1 THROUGH DSR-8

PRE-FILING DATE: TUESDAY, OCTOBER 11, 1994
PUBLIC HEARING DATE: TUESDAY, FEBRUARY 7, 1995

DONALD S. ROFF
INDIANAPOLIS POWER & LIGHT COMPANY
1994 ELECTRIC RATE CASE

Revised depreciation rates are recommended as a result of a depreciation study. The changes recommended affect the composite depreciation rates for each of the functional property groups: Steam Production, Other Production, Transmission, Electric Distribution and General Plant. The recommended rates for Steam Production Plant recognize 1994-1995 planned (pending) construction activity and beyond 1995, recognize future interim additions based on actual IPL experience for certain generating units, and the results of the dismantlement study performed by TLG Services, Inc. The recommendations for Plant follow the basic accounting principle that the timing of expenses should match the receipt of revenues, and also follows the basic depreciation accounting concept that interim additions and retirements should be fully recovered at retirement. The recommended rates for Transmission, Electric Distribution and General Plant are calculated on a remaining life basis using the Average Life Group Procedure. Recognition is given to the requirement that future net salvage be included in the calculation of remaining life depreciation rates.

Petitioner's Exhibit DSR
I.U.R.C. Cause No. 39938

Direct Testimony of Donald S. Roff
Senior Manager
Deloitte & Touche LLP

Index

Exhibits

DIRECT TESTIMONY OF DONALD S. ROFF
SENIOR MANAGER
DELOITTE & TOUCHE LLP

Q1. Please state your name and business address.

(a) My name is Donald S. Roff, and my business address is 2200 Ross Avenue, Dallas, Texas.

QUALIFICATIONS

Q2. What is your occupation?

(a) I am a Senior Manager in the firm of Deloitte & Touche. Deloitte & Touche is one of the largest international public accounting firms in the world, serving organizations in all major segments of the economy - government, public utilities, transportation, manufacturing, commerce, insurance, colleges and universities, hospitals and service organizations. I joined Deloitte Haskins & Sells (DH&S) in 1985. DH&S and Touche Ross & Co. merged in 1989 to form Deloitte & Touche. My prior associations were with Gilbert Associates, Inc. and Ernst & Whinney.

Q3. Please describe your educational background, and business and professional experience.

(a) I am a professional engineer and a graduate of Rensselaer Polytechnic Institute. I have over 20 years of experience in the areas of depreciation and valuation.

My education, training and experience are described in more detail in the document marked for identification as Petitioner's Exhibit DSR-1. Among the utilities for which I have participated in the preparation of depreciation studies in the last few years are:

- Central Power & Light Company
- Consumers Power Company
- Kentucky Utilities Company
- Nevada Power Company
- Potomac Electric Power Company
- Public Service Electric and Gas Company

PURPOSE OF TESTIMONY

Q4. What is the purpose of your testimony in this proceeding?

(a) I have been asked by the Indianapolis Power & Light Company (IPL) to perform a study as to the book depreciation rates required to provide for recording and accrual of investment-related costs, which include cost of removal and credit for salvage, for electric properties in the manner required by depreciation accounting principles and the accounting rules adopted by the Indiana Utility Regulatory Commission (I.U.R.C.) that are applicable to IPL. The property involved is Steam, Common Steam and Other Production, Transmission, Electric Distribution, and General Plant. Some of the Common Steam Production Plant, most of General Plant and all of the other property is used for electric operations. In the course of the study, I prepared the documents marked as Petitioner's Exhibits DSR-2 through DSR-8, which are identified and discussed in this testimony.

Q5. Have you been involved in any depreciation study for IPL prior to the current engagement?

(a) Yes. I participated in the preparation of a depreciation study for IPL's Common Steam Production, Steam Heat Distribution and General Plant, which was presented to the I.U.R.C. in IPL's last steam rate case (Cause No. 39440). This case was resolved by settlement. Pursuant to the Stipulation and Settlement Agreement which was approved by the I.U.R.C. on January 13, 1993, IPL's request for approval for new steam depreciation rates was dismissed without prejudice and IPL was authorized to continue to use its existing steam depreciation rates.

Q6. Please describe your involvement in the depreciation study submitted in Cause No. 39440 regarding IPL's steam depreciation study.

(a) My involvement included supervision of IPL personnel in the collection of accounting data, conduct of life analyses of all accounts, evaluation of results, and preparation of summary schedules and report.

BASIS FOR RECOMMENDED DEPRECIATION RATE CHANGES

Q7. Have you prepared a written report regarding the methodology used in your current depreciation study and the results of that study?

(a) Yes. The report has been marked for identification as Petitioner's Exhibit DSR-2 and consists of a cover letter summarizing the results, a discussion of the methodology followed in the study and six schedules showing the bases for calculating the recommended depreciation rates, how the Production Plant rates were calculated and how the recommended rates compare to the existing depreciation rates.

Q8. What is the source of the data used to prepare Petitioner's Exhibit DSR-2?

(a) The data used to prepare the report were acquired from numerous sources, including but not limited to, IPL business records and other sources identified in the report.

Q9. Is the type of data reflected in Petitioner's Exhibit DSR-2 normally used in your business for the purpose of a depreciation study?

(a) Yes, it is.

Q10. As of what time was your depreciation study performed?

(a) My study was performed as of December 31, 1993.

Q11. Was this study conducted under your supervision and direction?

(a) Yes, it was. I conducted certain aspects myself and utilized associates for conducting other aspects. My associates and I jointly directed IPL personnel in their collection of data utilized for the study.

Q12. Please describe your depreciation study and the involvement of IPL personnel, your staff, and yourself in the study so that you could formulate your recommendations for changes in IPL's depreciation rates.

(a) A depreciation study consists of four basic elements, Data Collection, Analysis, Evaluation and Calculation. My study combined these elements into the following four steps:

(1) Life Analysis and Evaluation of Results

(2) Salvage and Cost of Removal Analysis and Evaluation of Results

(3) Determination of Mortality Characteristics

(4) Calculation of Applicable Depreciation Rates

My associates and I reviewed Company accounting records or summaries of such records prepared by Company personnel; conducted analyses of past experience; conducted on-site investigations of property; held discussions with IPL personnel concerning such records and data, the results of our analyses of such records, and the significance of past experience to the future; reviewed the last depreciation study of IPL's electric utility property and the study of IPL's General Plant prepared for Cause No. 39440; examined information, testimony and orders about the depreciation rates of other Indiana utilities; reviewed IPL power plant construction budgets and resource plans; reviewed the dismantlement studies prepared by TLG Services, Inc.; reviewed IPL's unit optimization program and data concerning past activities relative to this program; selected the mortality characteristics appropriate for calculating depreciation rates applicable to IPL's electric utility property; and calculated the rates and compared them with IPL's existing rates and with the existing rates of other Indiana electric utilities. I was personally involved to some degree in each of these activities, and all were performed under my supervision and direction.

Q13. As a result of your participation in and direction of the study, are you sufficiently familiar with the electric utility property and operations of IPL to express an opinion as to the appropriate depreciation rates for that property?

(a) Yes, I am. My opinion about appropriate depreciation rates not only reflects my experience in the determination of such rates and the principles to be reflected therein, it also reflects a thorough investigation by me of the property, past retirement experience and significance of that experience to the future, the utility's operations, and the utility's planning. I am personally familiar with these matters as a result of the investigations previously described, my work in connection with the depreciation study submitted in Cause No. 39440, my analyses of past IPL experience and evaluation of its significance, and inspections and personal observations of IPL's property by me and my associates.

PURPOSE OF DEPRECIATION STUDY

Q14. Please explain the purpose of your depreciation study.

(a) A depreciation study is an effort to predict the future. Therefore, the purpose of my study was to accurately estimate the mortality characteristics applicable to the property in the future, and to use the characteristics to determine appropriate rates for accrual of depreciation expenses. Petitioner's Exhibit DSR-2 and later sections of this testimony describe the features of my study to enhance the consistency of the results with accounting principles and with the Uniform System of Accounts, and how these mortality characteristics were determined and were used to calculate the depreciation rates I recommend.

Q15. Is it commonly recognized that a depreciation study is an effort to predict the future?

(a) Yes, it is. Depreciation literature abounds with discussions of the requirement that depreciation rates reflect the current best estimates of the impact of expected future events.

Q16. Can you provide examples of this literature?

(a) Yes, I can. I have included in the document marked for identification as Petitioner's Exhibit DSR-3, an excerpt from the NARUC publication, Public Utility Depreciation Practices,* and in the document marked for identification as Petitioner's Exhibit DSR-4, an excerpt from the American Gas Association and Edison Electric Institute publication, An Introduction to Depreciation of Public Utility Plant and Plant of Other Industries. As can be seen from the excerpts, these publications recognize the importance of estimating what will happen to the property in the future.

RESULTS OF DEPRECIATION STUDY

Q17. What are the results of your depreciation study?

(a) Functional composite rates are currently used to calculate depreciation expenses. As a result of my study, I recommend that account rates be used in the future, so that changes in property mix are automatically reflected in depreciation accruals. The existing functional composite rates and the functional composite rates which would result from my recommended account rates are shown below, based on the December 31, 1993, depreciable plant balances applicable to electric operations:

* Compiled and Edited by Depreciation Subcommittee of The NARUC Committee on Engineering, Depreciation, and Valuation of the National Association of Regulatory Utility Commissioners

	Composite Rate	
Functional Group	Existing %	Resulting From Recommended Account Rates %
Steam Production Plant	2.87	3.59
Common Steam Production Plant	2.72	2.72
Other Production Plant	2.87	3.46
Transmission Plant	2.42	3.56
Electric Distribution Plant	5.11	4.68
General Plant	4.30	5.77
Total Electric Plant	3.45	3.95

The recommended rate for Common Steam Production Plant is the existing composite rate for this functional group authorized through the settlement of I.U.R.C. Cause No. 39440. The recommended account rates for the other property are the result of my study. The above summary is taken from Schedule 1, Column 5 of Petitioner's Exhibit DSR-2.

Q18. What mortality characteristics are used in your study?

(a) The mortality characteristics are (1) generating unit retirement dates or average service lives, (2) dispersion (variation) of retirements around average life defined either by pending construction and interim addition and retirement ratios, or by Iowa-type dispersion patterns, and (3) salvage, cost of removal and net salvage factors.

Q19. Where in your report do you show the mortality characteristics used to compute your recommended depreciation rates?

(a) The generating unit retirement dates used to calculate the recommended Steam and Other Production Plant rates are shown in Column 6 of Schedule 2 of Petitioner's Exhibit DSR-2. The interim addition and retirement ratios, and interim salvage, cost of removal and net salvage factors and terminal net salvage amounts used to calculate the recommended rates for Steam and Other Production Plant are shown on Schedule 3 of Petitioner's Exhibit DSR-2. The average service life, retirement dispersion pattern identified by Iowa curve type, and salvage, cost of removal and net salvage factors used to calculate each recommended rate for Transmission, Electric Distribution and General Plant are shown on Schedule 4 of Petitioner's Exhibit DSR-2.

Q20. Where in your report do you show the mortality characteristics which underlie IPL's existing depreciation rates?

(a) Schedules 3 and 4 of Petitioner's Exhibit DSR-2 also show the mortality characteristics used to calculate IPL's existing depreciation rates, but include only net salvage factors. A net salvage factor is calculated by subtracting a cost of removal factor from a salvage factor. These factors are expressed in terms of percentages of depreciable investment. Positive net salvage factors result when salvage exceeds cost of removal, and negative net salvage factors result when cost of removal exceeds salvage. While the net salvage factors used to calculate IPL's existing depreciation rates are known, the existing component salvage and cost of removal factors are not known.

Q21. What are interim additions and retirements?

(a) Interim additions are any additions made after the original construction of a generating unit or station. Interim retirements are any retirements made prior to the final (terminal) retirement of a unit or station. A generating station experiences capital additions and retirements over its life as items are replaced and items not originally required are added. This addition and retirement activity is required to maintain the reliability of the facility, thus assuring that the planned operating life occurs. For example, a condenser requiring replacement of tubes would cease to function if replacement did not occur. The old tubes are interim retirements, and the new tubes are interim additions. Not making the replacement would cause the unit to be retired. Replacement of the tubes would cause the unit to continue to operate. Thus, the interim additions and retirements are linked to the remaining life span.

Q22. What interim additions and retirements were considered in your study?

(a) The recommended rates for Steam and Other Production Plant of all units recognize the 1994-1995 pending construction activity and future interim retirements for all units. For Pritchard Units 1 through 6 and Stout Units 3 through 6, the recommended rates also reflect interim additions beyond 1995, including those needed to reach their expected 60-year life spans.

Q23. What rate calculation methodologies did you use in your study?

(a) I used the remaining life rate life span calculation procedure for Steam and Other Production Plant. This procedure is demonstrated on Page 3 of Schedule 6 of

Petitioner's Exhibit DSR-2, using Stout Account 312.1, Boiler Plant Equipment, as an example. The recommended rates for Transmission, Electric Distribution and General Plant are calculated on a remaining life basis using the Average Life Group (ALG) calculation procedure, as are the existing rates. Each depreciable group has a unique depreciation rate, and the groups used for my study are the primary plant accounts and subaccounts listed in Column 1, Schedule 1 of Petitioner's Exhibit DSR-2.

REASONS FOR DEPRECIATION RATE CHANGES

Q24. What are the primary reasons for the depreciation rate changes you found are needed?

(a) The recommended changes in the depreciation rates for Steam and Other Production Plant are due to the direct recognition of certain future interim additions and all future interim retirements, and to a decrease (more negative) in terminal net salvage. The most significant change for Steam Production Plant was to net salvage and for Other Production Plant was to life.

The primary reason for the Transmission and Electric Distribution Plant changes is the net effect of increases in average service lives and decreases in net salvage factors (less positive or more negative). The primary reasons for the General Plant changes are (1) the same as in the case of Transmission and Electric Distribution Plant and (2) a change in mix of the surviving assets.

Petitioner's Exhibit DSR
I.U.R.C. Cause No. 39938

ACCOUNTING AND REGULATORY FRAMEWORK REFLECTED IN STUDY

Q25. Please explain the purpose of depreciation accounting.

(a) The most widely recognized definition of depreciation accounting is that of the American Institute of Certified Public Accountants, which states:

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

Several aspects of this definition are important:

- Salvage (net salvage) is to be recognized;
- The distribution is to be over the useful life of the assets;
- The property may be a group of assets;
- Depreciation accounting is a process of allocation, not valuation; and,
- Most important, depreciation accounting must be both systematic and rational.

To be both systematic and rational, depreciation accounting should, to the extent possible, reflect the consumption of physical assets. It is not difficult to make depreciation accounting systematic through the use of formulas. To be rational, the pattern of depreciation should match either the consumption of the facilities or the revenues generated by the facilities, which is accomplished by the pattern of depreciation rates. Thus, for property expected to be utilized at a constant rate over its lifetime, the depreciation rate will be constant. This matching between asset consumption and the recording of that consumption ensures that financial statements reflect the results of operations and changes in financial position as accurately as possible. The matching principle reflects the fact that *both* the cause and the effect are required to be recognized for financial accounting purposes.

To implement the matching concept for depreciation accounting, the asset's service life, salvage value and cost of removal must be identified. The determination of an asset's actual mortality characteristics is made through conducting a depreciation study that includes the use of these characteristics to calculate depreciation rates or provisions. For accounting purposes, it is commonly assumed that consumption occurs evenly over the service life; that is, on a straight-line basis implying a constant depreciation rate.

This purpose of depreciation accounting forms the accounting portion of the framework under which my study was conducted. My study was conducted in a manner that enhances compliance of the results with the purpose of depreciation accounting, and with the depreciation accounting concept of the Uniform System of Accounts (USOA) for electric utilities adopted by the I.U.R.C. and followed by IPL.

Q26. Please describe the concept of depreciation that is inherent in the depreciation accounting rules adopted by the I.U.R.C.

(a) The USOA establishes these depreciation accounting rules through the depreciation-related definitions shown on Page 5 of Petitioner's Exhibit DSR-2. These definitions form the regulatory portion of the framework under which my study was conducted. My study gave recognition to the causes of retirement that the USOA definition of depreciation requires to be considered. The mortality characteristics were selected with these definitions in mind. For example, as is evident from the wording of the salvage value and cost of removal definitions, it is the salvage that is expected to be received and the cost of removal that is expected to be incurred, both measured as of the time of receipt or incurrence, that is required to be recognized in IPL's depreciation rates.

Q27. Why is net salvage required to be included in the calculation of depreciation rates?

(a) The reason for the consideration of net salvage in the development of depreciation rates is discussed in the quotation from the NARUC publication Public Utility Depreciation Practices, which I have included on the document marked for identification as Petitioner's Exhibit DSR-5. As is explained there, the acquisition and use of property ultimately results in the need to abandon or remove the property at the end of its useful life. Reflection of net salvage in depreciation rates permits the allocation of abandonment and removal costs over the life of the property and recovery of these costs from the consumers who benefit from the use of the property.

Q28. Please explain how you enhanced the compliance of the depreciation rates you recommend with the accounting and regulatory framework you have described.

(a) There are several influences on this effort which will be discussed hereafter:

- The matching principle;
- The unit optimization program for generating units;
- Power plant interim additions and retirements;
- Retirement dispersion; and,
- Certain IPL accounting practices.

MATCHING PRINCIPLE

Q29. Please explain the influence of the matching principle on your study.

(a) The matching principle has a particular influence on how a depreciation study of power plants is conducted. Its significance to my study is explained on Pages 5 through 7 of Petitioner's Exhibit DSR-2. When sufficient historical data are available for analysis results to be meaningful, the cause and effect are reflected automatically, because both cause and effect are integral to such history. This is the case for property other than power plants. The nature of location-type property (property recorded by specific location, such as power plants) is that both the cause and the effect are reflected in history only after terminal retirements of major elements (i.e., generating units) or total locations (i.e., complete power plants) have taken place. Automatic incorporation of cause and effect occurs when terminal retirements have taken place, because history will then include original installations, additions made for plant enhancements and component replacements, component replacement retirements, and final retirements, and the life resulting from all this activity.

Without this terminal retirement experience, any method of life analysis, including the actuarial method I used for Transmission, Electric Distribution and General Plant, will reflect only the retirements for replacement of components. Accordingly, this method will usually indicate a higher average service life and less dispersion than is applicable to the property. IPL has some terminal retirement experience for individual generating units, but it is not sufficient to use directly as the basis for determining depreciation rates. Therefore, I had to estimate future events by simulating the future for Steam and Other Production Plant. I chose to identify dispersion through pending construction amounts and the interim ratios described earlier. Pending construction is that expected to be closed to plant-in-service during 1994 and 1995 for existing generating units. I did not have to take this approach for the Transmission, Electric Distribution and General Plant location-type property, because these property groups have had sufficient terminal retirement experience for analysis results to be meaningful.

Q30. Was there sufficient terminal retirement experience for Steam and Other Production Plant to use as a basis for determining service life or for calculating depreciation rates?

(a) The limited terminal retirements of steam generating units and the lack of terminal retirements for combustion turbine and diesel units precluded the use of history as a basis for determining service life or for calculating depreciation rates.

Q31. What use of historical experience for Steam and Other Production Plant was made?

(a) The Company has had sufficient interim activity experience which was used as a basis for determining the interim addition and retirement rates used in the calculation of depreciation rates.

GENERATING UNIT LIFE SPANS

Q32. What life spans are used in your study for the steam generating units classified as Steam Production Plant?

(a) IPL has a unit optimization program for the refurbishment of certain generating units. Including refurbishment, IPL expects generating unit life spans of 60 years, and without refurbishment, IPL anticipates life spans of 40 years. The depreciation rates I recommend are based on life spans of 60 years for Stout Units 3 through 6, Pritchard Units 1 through 6 and Petersburg Units 1 and 2. My study uses life spans of 40 years for Petersburg Units 3 and 4 and Stout Unit 7.

Q33. What is the relationship between these life spans and the interim additions reflected in your study?

(a) The matching principle and need for consistency of depreciation rate calculation components dictated that I handle steam generating units that have been in IPL's unit optimization program differently from the other units. For Pritchard Units 3 through 6 and Stout Units 5 and 6, the generating unit retirement dates I used for rate calculations are those expected by IPL including refurbishment, which represents a 60-year life span. For these units, I incorporated into my rate calculations the 60-year life span and all the past and expected future capital expenditures that will produce their 60-year life spans. I also handled Pritchard Units 1 and 2 and Stout Units 3 and 4, in this manner.

Petersburg Units 3 and 4 and Stout Unit 7 are not yet old enough to embark upon the assessments necessary to evaluate equipment condition, so for purposes of depreciation rate calculation, the retirement dates are based on a life span of 40 years. Correspondingly, I included no future interim additions in the rate calculation. I took this approach to calculating the recommended rates, because the matching principle requires either that the cause (expected future expenditures) and the effect (a 60-year life span) both be included for calculating depreciation rates, or that both be excluded. While some level of future interim additions will be required for these units to reach 40-year life spans, I excluded these additions to be consistent with the basis for the Steam Production Plant depreciation rates the I.U.R.C. authorized for Indiana Michigan Power Company in Cause No. 39314 and for PSI Energy, Inc. in Cause No. 37414-S2. Inclusion of these additions would have resulted in higher depreciation rates.

Even though Petersburg Units 1 and 2 are not yet old enough to embark upon the assessments necessary to evaluate equipment condition, I adopted 60-year life spans in view of the recent Commission authorization for IPL to proceed with adding a scrubber to these units. However, I handled the future interim additions in the same manner as Stout Unit 7 and Petersburg Units 3 and 4, and I excluded the scrubber additions. Had I handled the future additions in the same manner as the other units having 60-year life spans, my recommended rates for Petersburg would have been higher.

In summary, the life spans and treatment of post-1995 interim additions in my study are as follows for the steam units:

Station and Unit	Life Span Used in Study	Inclusion of Post-1995 Interim Additions
E.W. STOUT PLANT		
Unit 3	60	Yes
Unit 4	60	Yes
Unit 5	60	Yes
Unit 6	60	Yes
Unit 7	40	No

H.T. PRITCHARD PLANT		
Unit 1	60	Yes
Unit 2	60	Yes
Unit 3	60	Yes
Unit 4	60	Yes
Unit 5	60	Yes
Unit 6	60	Yes
PETERSBURG PLANT		
Unit 1	60	No
Unit 2	60	No
Unit 3	40	No
Unit 4	40	No

Q34. What is the approximate amount of post-1995 interim additions for inclusion in your study for Steam Production Plant?

(a) The total amount of the post-1995 interim additions reflected in this study is approximately $65,600,000.

Q35. How were interim additions handled for the diesel and combustion turbine units classified as Other Production Plant?

(a) For this property I included interim additions for all the units.

RETIREMENT DISPERSION

Q36. Please explain retirement dispersion and its significance to IPL's depreciation rates.

(a) Dispersion is merely the variation of the age of retirements around average service life, and is an inherent characteristic of the group concept of depreciation accounting that is incorporated into the Uniform System of Accounts. The depreciation rates are based on the recognition that each depreciable property group has an average service life. However, very little of the property is *average*. The group concept carries with it recognition that most property will be retired at an age either less than or greater than the average service life, and will be recorded as being fully depreciated at retirement, no matter at what age the retirement occurs. In contrast to the item concept of depreciation accounting, gains or losses are not recorded for ordinary retirements, and depreciation accruals do not cease until the property is retired.

The identification of dispersion is inherent in the determination of mortality characteristics, and dispersion is recognized when the depreciation rates are calculated. For Production Plant, my study used pending construction additions and interim addition and retirement ratios to define the dispersion. For the other property, my study used Iowa-type standard dispersion patterns.

Q37. What are Iowa-type dispersion patterns?

(a) The Iowa-type dispersion patterns that are widely used by electric and gas utilities were devised empirically about 60 years ago to provide a set of standard definitions of retirement dispersion patterns. The L series indicates the mode of the frequency distribution is to the Left of average service life, the R series to the Right and the S series at average service life, and therefore, Symmetrical. There is also an O series which has the mode at the Origin, thereby identifying a retirement pattern that has the maximum percentage of original installations retired during the year of placement.

Q38. Please explain the document marked for identification as Petitioner's Exhibit DSR-7.

(a) Three of the Iowa-type dispersion patterns are illustrated by the frequency distributions on Petitioner's Exhibit DSR-6. The curve designation numbers indicate the range of dispersion, with the high number (4) indicating a narrow dispersion pattern and the low number (1) indicating a wide dispersion pattern. For example, the R1 curve shown on the Exhibit indicates that retirements start immediately and that some of the property will last twice as long as the average service life. The frequency distributions translate to survivor curves, which are the most recognizable form of the Iowa curves. Other families of such patterns exist, but are not as widely used as the Iowa-type.

ACCOUNTING PRACTICES

Q39. Please explain the IPL accounting practices that influenced your study.

(a) The most significant influence on my study results from the fact that the average age of original installations at retirement is equal to the average service life, meaning that the average age of surviving property at retirement will be higher than the average service life. Accounting practices that determine the age of retired property control the property ages incorporated in the historical data utilized for my study.

Since I utilized unaged data for analyzing salvage and cost of removal experience, IPL's practices of determining the year placed in service (vintage) for Transmission and Electric Distribution Plant property groups influenced my determination of the salvage and cost of removal factors for this property. Two such aging practices are reflected; basing the vintage of retired property on a first-in, first-out (FIFO) basis, and basing the vintage on construction records. Schedule 5 of Petitioner's Exhibit DSR-2 (which I will discuss later) shows several cost of removal factor changes I made to recognize the influence of these accounting practices on my study. These changes are but a small step toward the future cost of removal factors that IPL's history indicates should be used to calculate depreciation rates.

An additional influence is IPL's practice of crediting certain construction cost reimbursements to retirement work orders.

Q40. Please explain the influence of the FIFO aging basis on your study.

(a) My conclusions for several Transmission and Electric Distribution Plant property groups are influenced by the FIFO practice. FIFO aging is an accounting convention whereby the property retired is assumed to be the oldest surviving property. This has several influences on my study:

- The age of retired amounts is high, which causes low original cost amounts to be retired and average service lives to be longer than might otherwise be indicated;

- The range of age of retired amounts is small, which causes little variation (dispersion) of retirements around average service life;

- The portion of retired items that are young enough to warrant reusing is much larger than would be expected for property of the age assumed for determining retirement amounts, which causes salvage factors (recorded salvage amounts divided by original cost retired) to be high; and,

- The cost of removal factors (recorded cost of removal amounts divided by original cost retired) to be high, which causes the factors to be closer to those expected upon retirement of all the surviving property.

The logical and most appropriate response to this situation is to not use history as the sole basis for net salvage determinations.

Q41. Please illustrate these influences.

(a) An example of property aged on a FIFO basis is Account 364, Poles, Towers & Fixtures. Schedule 4, Column 5 of Petitioner's Exhibit DSR-2 shows that the selected average service life is 30 years. Column 2 of Schedule 5 shows that the age of the property retired from Account 364 for 1989 through 1993 was 31.6 years, which demonstrates the high age of retirements relative to average service life resulting from this accounting practice. Column 6 of Schedule 4 shows that the selected Iowa curve is S5, which is more narrow than the S3 pattern shown on Petitioner's Exhibit DSR-6 and is the second most narrow of the Iowa symmetrical dispersion patterns. Schedule 4, Column 7 of Petitioner's Exhibit DSR-2 shows that the selected salvage factor is 60%. This suggests that 60% of the original installed cost would be recovered through salvage. This is unrealistic for poles and hardware that, on average, will be 30 years old at retirement. In view of the large changes found to be needed for Transmission and Electric Distribution Plant net salvage factors, no salvage factor adjustments were made to account for this situation. If adjustments had been made, the depreciation rates would have increased.

Column 5 of Schedule 5 shows that the cost of removal factor based solely on history is 200%. This suggests that 200% of the original installed cost would be expended to remove the retired poles and hardware, which is realistic for property that, on average, will be 30 years old at retirement. Column 8 of Schedule 5 shows that I decreased the selected cost of service factor by 5% to reflect this situation. The other property groups to which this situation applies are indicated in the discussion of study results on Pages 20 through 33 of Petitioner's Exhibit DSR-2.

Q42. Please explain the importance of basing the vintage of retirements for some depreciable property groups on the years of original construction.

(a) This aging convention causes the average dollar ages of retirements of some Transmission and Electric Distribution Plant property groups to be young relative to the expected age of surviving property at retirement, a normal situation when the vintage of retired property is determined from construction records. This situation improves the validity of salvage factors, but they still overstate the factors that can be expected for property retired at an age, on average, equal to the average service life. This situation reduces the validity of cost of removal factors, because the age of experienced retirements is less than the expected age of the surviving property upon retirement. Again, the logical and most appropriate response to this situation is to not use history as the sole basis for net salvage determinations.

Q43. Please illustrate these influences.

(a) An example of property aged on the basis of construction records is Account 362, Substation Equipment. Schedule 4, Column 5 of Petitioner's Exhibit DSR-2 shows that the selected average service life is 40 years. Column 2 of Schedule 5 shows that the age of the property retired from Account 362 for 1989 through 1993 was only 19.0 years, which demonstrates the low age of retirements relative to average service life resulting from this accounting practice. Column 6 of Schedule 4 shows that the selected Iowa curve is S-0.5, which is wider than any of those shown on Petitioner's

Exhibit DSR-6. Schedule 4, Column 7 of Petitioner's Exhibit DSR-2 shows that the selected salvage factor is 15%, suggesting that 15% of the original installed cost would be recovered through salvage, which may be unrealistic for substation equipment that, on average, will be 40 years old at retirement. In view of the large changes found needed for Transmission and Electric Distribution Plant net salvage factors, no salvage factor adjustments were made for this situation. If adjustments had been made, the depreciation rates would have increased.

Column 5 of Schedule 5 shows that the cost of removal factor based solely on history is 20%, suggesting that 20% of the original installed cost would be expended to remove the retired substation equipment, which is unrealistic for property that, on average, will be 40 years old at retirement. Column 8 of Schedule 5 shows that I increased the selected cost of removal factor by 5% to reflect this situation. The property groups to which this situation applies are indicated in the discussion of study results on Pages 20 through 33 of Petitioner's Exhibit DSR-2.

Q44. Please explain the influence on your study of crediting some construction cost reimbursements to retirement work orders.

(a) IPL records some of the third-party and customer reimbursements for construction by crediting them to retirement work orders, making them appear to be salvage. Since such reimbursements are a characteristic of the added property, not of the retired property, the reimbursements credited to retirement work orders were segregated for the period 1983 through 1993 and related to additions rather than to retirements in order to provide the appropriate credit in expectation that such reimbursements will continue. Treating the amounts as if they are salvage would result in overstating the resultant salvage factors.

CALCULATION OF THE RECOMMENDED RATES

Q45. Please explain the remaining life technique you used to calculate the depreciation rates you recommend.

(a) I calculated a remaining life rate for each depreciable property group using the following formula:

$$\text{Rate} = \frac{\text{Plant Balance - Future Net Salvage - Book Reserve}}{\text{Average Remaining Life}}$$

This formula illustrates that a remaining life rate recognizes the book reserve position. My calculations utilized dollar amounts for the numerator terms, with conversion of the resulting annual depreciation expense amounts to a percentage rate as the last step in the calculation. The format of my use of this formula to calculate the rates for Steam and Other Production Plant was different from the format I used for the other property groups, as described below.

Both the numerator and denominator of the above formula are future oriented. The existing depreciable plant balance less net salvage is the total investment cost to be recorded through depreciation. Subtracting the book reserve calculates the investment cost to be recorded in the future. Dividing by the average remaining life of the existing plant balance determines the annual amount to be recorded. Dividing the annual amount by the existing plant balance and converting to a percent results in the annual depreciation rate.

Q46. Please explain how your recommended depreciation rates were calculated.

(a) A straight-line remaining life rate was calculated for each Steam and Other Production Plant depreciable property group using the formula shown above and the procedure described on Pages 16 and 17 of Petitioner's Exhibit DSR-2 and illustrated on Schedule 6 of the Exhibit. A straight-line remaining life rate was calculated for each Transmission, Electric Distribution and General Plant property group using the ALG procedure described on Page 17 of Petitioner's Exhibit DSR-2. All of the rate calculations incorporate the commonly used *half-year* convention, whereby all additions and all retirements are assumed to occur, on average, at midyear.

Q47. Why is it appropriate to use the half-year convention for calculating Production Plant depreciation rates?

(a) My use of this convention is in accordance with the average installation dates of IPL's units (July for steam units and June for diesel and combustion turbine units), with the expected life spans, and with the fact that IPL does not believe, and I agree, that any one month for unit retirements is more probable than any other month.

Q48. Why did you use the remaining life technique?

(a) Remaining life rates provide for full recording and cost allocation over the remaining life of surviving property, thus improving the match between actual property consumption and the recording of depreciation. The remaining life technique compensates for any past over- or underaccruals of depreciation and plant and reserve transactions different from those anticipated by the mortality characteristics used to calculate the existing rates. The remaining life technique also limits depreciation to the utility's investment, net of expected salvage and cost of removal - no more and no less.

Q49. Please explain the appropriateness of using future net salvage to calculate remaining life rates.

(a) Complying with the definitions in the USOA shown on Page 5 of <u>Petitioner's Exhibit DSR-2</u> requires estimation of end-of-life salvage and cost of removal. Thus, cost change is a factor that always must be considered when evaluating the significance of history. Cost change is always represented when such experience is analyzed, as the numerator of the formula for calculating salvage and cost of removal factors is always salvage and cost of removal amounts recorded at the time the property is removed or abandoned and the denominator is always retirement amounts recorded at original cost.

When history is unavailable, not meaningful, or inconclusive, specific cost estimates may be required, as is the case for IPL's power plants. Since such estimates are used to reflect future costs, the future salvage and cost of removal amounts are estimated at the cost level at the time of receipt (salvage) or incurrence (cost of removal).

The NARUC publication entitled Public Utility Depreciation Practices discusses future net salvage and how studies can be conducted to ensure that both past and future net salvage are correctly reflected in depreciation rates. That volume states on page 91 that "estimated future net salvage" is to be used when calculating remaining life depreciation rates.

Q50. Please explain the interim retirement simulations you incorporated into the rate calculations for Steam and Other Production Plant.

(a) As an example, the simulations of interim retirements and terminal retirements for Stout Account 312.1, Boiler Plant Equipment, are shown on Pages 1 and 2 of Schedule 6 of Petitioner's Exhibit DSR-2. Once there have been sufficient terminal retirements, the life analysis procedure I used for the other location-type property and for the mass-type property (property for which specific location identification is not maintained as a component of property records) can be used, and such simulations may no longer be needed.

LIFE ANALYSIS PORTION OF STUDY

Q51. Please describe the life analysis portion of your study.

(a) The life analysis concerns the determination of generating unit retirement dates, average service lives, and retirement dispersion identified by pending construction and interim addition and retirement ratios or by standard curve types. The life analysis for Steam and Other Production Plant consisted of a forecast (life estimation) and a historical analysis (life analysis), and for other property consisted of a historical analysis. My analyses of aged data incorporate the half-year convention.

Q52. Please describe your Life Analysis for Steam and Other Production Plant.

(a) For Steam and Other Production Plant, the Life Analysis required two steps. The first step was the estimation of the retirement date of each generating unit or group of units. The second step was the calculation of past interim addition and retirement ratios. The planned generating unit retirement dates were provided by IPL, and are shown in Column 5 of Schedule 2 of Petitioner's Exhibit DSR-2. In order to maintain the required link between future interim additions and the life spans resulting therefrom that I discussed earlier, the retirement dates shown in Column 6 were used for calculating the recommended depreciation rates.

Q53. How were the interim additions and retirements derived?

(a) The interim addition and retirement ratios were determined from actual IPL addition and retirement experience. This analysis is explained on Page 10 of Petitioner's Exhibit DSR-2.

Q54. Please describe your life analysis for property other than power plants.

(a) My life analysis for this property, which is made up of both location-type and mass-type property, is described on Pages 10 and 11 of Petitioner's Exhibit DSR-2. Life analysis involves the measurement of history, but does not determine its applicability to the surviving property. In some instances, history can be lacking or an inappropriate indication of what can be expected for the surviving property. Therefore, an evaluation is required to determine the extent to which history is a reasonable indication of the future. The need for these evaluations is discussed on Pages 14 through 16 of Petitioner's Exhibit DSR-2, and their effects on my study are discussed on Pages 20 through 33.

SALVAGE AND COST OF REMOVAL ANALYSIS PORTION OF STUDY

Q55. Please explain the Salvage and Cost of Removal Analysis for the power plant portion of your study.

(a) The Salvage and Cost of Removal Analysis for this property is described on Pages 12 and 13 of Petitioner's Exhibit DSR-2. Since IPL has no terminal power plant dismantlement experience, the terminal salvage and cost of removal could not be based on history. Instead, terminal net salvage was based on estimates at the cost level at the time of dismantlement derived from the dismantlement study of TLG Services, Inc.

As an example, the result of my simulation of the terminal net salvage amount for Stout Account 312.1 is shown in Column 12 of Page 3 of Schedule 6 of Petitioner's Exhibit DSR-2. Use of TLG's site-specific study is the best basis for reflecting negative net salvage for the power plants.

Q56. Please explain how you used the TLG estimates to simulate the terminal dismantling cost and salvage for Steam and Other Production Plant.

(a) TLG Services, Inc. prepared the dismantling cost and salvage estimates discussed by Mr. LaGuardia in his testimony in this proceeding. I used Mr. LaGuardia's estimates to calculate the net cost of removal amounts at the estimated cost level when the dismantlement of each plant is expected to occur. As Mr. LaGuardia discusses, dismantlement is expected immediately upon the retirement of the last unit at each plant. I converted the TLG estimates at the 1993 cost level to the cost level when each plant is expected to be demolished, using labor escalation rates of 3.5% for 1994 through 1996 and 3.6% for 1997 and beyond provided by IPL (from the summary of Assumptions for Budgeting and Forecasting), and I allocated the resulting plant totals to accounts. I utilized labor escalation rates because the dismantlement process is labor-intensive, as is demonstrated by the fact that at least 75% of the dismantling costs shown on Page 27, Line 10 of Mr. LaGuardia's testimony are labor-related. Labor cost escalation rates are appropriate for incorporating dismantlement cost estimates into depreciation rate calculations. While it may be overly conservative to escalate salvage, I applied the labor escalation rates to all components of the TLG estimates. My cost escalation is to the midpoint of Mr. LaGuardia's dismantlement schedules for the steam units and to the retirement dates of the diesel and combustion turbine units. The result for Stout Account 312.1 is the amount of $42,967,202 shown in Column 12 of Page 3 of Schedule 6 of Petitioner's Exhibit DSR-2.

While I also estimated the interim net salvage in Column 10 of Page 3 of Schedule 6 of Petitioner's Exhibit DSR-2, the interim net salvage factor used to do so is based on actual IPL interim retirement experience.

Q57. You have used net salvage amounts to calculate the rates you recommend for power plants. What are these amounts expressed in terms of net salvage factors?

(a) The factors for the diesel and combustion turbine units are small. The factors for steam units are shown below:

Station	1993 Dismantlement Cost Level as a Percent of December 31, 1993, Depreciable Balances	Future Dismantlement Cost Level as a Percent of Terminal Retirement Balances
	%	%
Stout	17	38
Pritchard	25	43
Petersburg	6	25

The right-hand column reflects the projected balance at retirement for all units.

The Pritchard 1993 basis percentage is larger and Petersburg is smaller than Stout because Pritchard has the oldest units, thereby having had the longest time for cost increases to be reflected in the TLG 1993 cost estimates. Petersburg has the youngest units, thereby having the shortest time for cost increases to be reflected in the TLG estimates. The future cost basis reflects both the labor cost escalation and the terminal depreciable balances reflected in the rate calculations.

As is evident from the net salvage factors shown on Schedule 4 of Petitioner's Exhibit DSR-2, the future cost basis net salvage factors for Steam Production Plant are much lower than for Transmission and Distribution Plant.

Q58. Do you believe that past industry experience in removing power plants can be used to predict the terminal net salvage factors applicable to IPL's steam generating stations?

(a) No, which reinforces the need for the site-specific TLG estimates.

Q59. Please explain why you believe past industry experience is not suitable.

(a) The major reasons are the boiler design and the adoption of environmental regulations which will increase plant dismantlement and disposal costs. For example, several units are expected to still have some insulation containing asbestos at retirement that will require special removal procedures that are not included in most past experience.

Q60. Please explain the significance of boiler design.

(a) The past industry retirement experience is for an older type of boiler than the existing type. The boilers for Stout Units 1 and 2 are similar to the old style, being partly self-supporting and partly resting on foundations. The boilers for all other units are not designed in the same manner. These modern boilers are quite heavy and are hung by their tops from multistory steel superstructures. The combination of the weight of the boiler itself and the superstructure results in a much larger and more massive foundation. These superstructures and foundations will be costly to remove, as indicated by TLG Services, Inc.'s study results.

The large superstructures of modern electric generating units do not allow use of a wrecking ball for boiler dismantlement, and the explosive techniques commonly used for large buildings may not be safe. While blasting could be used to drop the boiler and its superstructure in a heap, the pile of materials that would need to be cut up for removal would contain residual stresses that may preclude safely cutting the materials. Therefore, a piecemeal removal procedure that resembles original construction procedures may be necessary for modern boilers, and is the assumption built into the TLG estimates. This method of boiler removal increases cost of removal, which decreases (makes more negative) net salvage.

Q61. Please explain the Salvage and Cost of Removal Analysis portion of your study for Transmission, Electric Distribution and General Plant.

(a) Salvage and cost of removal experience for 1979 through 1993 was the basis for determining the selected salvage, cost of removal and net salvage factors shown in Columns 8, 9 and 10 of Schedule 3 for power plants and in Columns 7, 8 and 9 of Schedule 4 of Petitioner's Exhibit DSR-2 for the other property, and the analysis is described on Pages 12 and 13 of the Exhibit.

Salvage and Cost of Removal Analysis involves the measurement of history, but does not determine its applicability for the future. An evaluation is required to determine if history is a reasonable indication of the future. In addition to the discussions herein concerning the need for these evaluations, the need is discussed on Pages 14 through 16 of Petitioner's Exhibit DSR-2, and their effects on my study are discussed on Pages 20 through 33.

Q62. Please explain how you estimated the future Transmission and Electric Distribution Plant cost of removal factors you discussed earlier.

(a) For certain Transmission and Electric Distribution Plant property groups, I selected cost of removal factors that are higher than experienced in the past, but that are only a small step toward cost of removal factors that are consistent with the average service lives used for rate calculations. How I accomplished this is shown on Schedule 5 of Petitioner's Exhibit DSR-2. First I calculated the actual 1989 through 1993 retirement ages shown in Column 2. I then calculated the expected ages upon retirement of all of the property surviving at December 31, 1993, from the recorded age distribution of this property and the average service lives and dispersion patterns I determined appropriate, and show these average ages in Column 3. Column 4 shows the actual historical cost of removal factors for the 1989 through 1993 retirements, and Column 5 shows selected factors based solely on that history. Column 6 shows the cost of removal factors that would have been produced if the 1989 through 1993 retirements of these property groups had been of the age expected upon retirement of the property surviving at December 31, 1993. Column 7 shows the differences between the total obligations in Column 6 and the history-only factors in Column 5. As is evident from the factor adjustments in Column 8, my selected cost of removal factors shown in Column 9 are but a small step toward the future cost of removal factors that IPL's past experience indicates are appropriate for calculating remaining life depreciation rates.

Q63. Please explain how you calculated the cost of removal factors that would have been produced if the 1989 through 1993 retirements had been of the age expected upon retirement of the property surviving at December 31, 1993.

(a) The document marked for identification as Petitioner's Exhibit DSR-7 shows my calculation for Account 364, Poles, Towers & Fixtures. Column 3, Lines 1 through 5, show the total annual retirements recorded during each of the years (1989 through 1993) shown in Column 1, and Column 5 shows the average dollar age of these retirements. The purpose of this Exhibit is to calculate the average vintage year of the actual retirements and what the average vintage year would have been if the retirements had been of an age equal to the average service life (30 years) and an age equal to the expected age of the surviving property upon its retirement (30.3 years). The first step is to calculate the average transaction or retirement year from the ages of the transaction years shown in Column 2 and the weighting calculated in Column 4. This age was 2.6 years (Column 2, Line 6) which when subtracted from December 31, 1993, shows that the average year of retirement was 1991 (Line 7). The average age of the 1989-1993 retirements was 31.61 years (Column 5, Line 6), which when subtracted from the average transaction year shows that the average vintage year was 1959 (Column 4, Line 8). The cost of removal recorded during 1989-1993 was 205% of the actual original cost retired (Line 10), and the salvage was 76% (Line 9). The remaining calculations involve only cost of removal.

Line 11 shows the selected average service life of 30 years, Line 12 shows the average remaining life (17.4 years) of the December 31, 1993, surviving plant balance, and Line 13 shows the average age (12.9 years) of this balance. Line 14 shows the average age of retirements on a whole life rate basis (30.0 years), and Line 15 shows the age on a remaining life rate basis (30.3 years, Line 12 plus Line 13).

Lines 16 and 17 show what the vintage years would have been if the retired property had been 30.0 years and 30.3 years old, respectively, rather than 31.6 years old. Vintages are utilized so that the Handy-Whitman Index of Public Utility Construction Costs could be used to estimate the original cost of this older property. Column 7 shows these indices for the three vintage years (1959.3, 1960.9 and 1960.6) involved in the estimate of the future cost of removal needed for the calculation of a remaining life rate for Account 364.

The concept behind the future cost of removal estimate is to trend the actual retirements of $1,330,207 (Column 3, Line 6) from the year 1959 to the year 1961 by dividing by 49 (Column 7, Line 8) and multiplying the result by 52 (Column 7, Line 17). This produces an adjusted original cost of about $1,400,000, which when divided into the recorded cost of removal amount produces a lower cost of removal factor than using the actual amount of $1,330,207. The actual calculation of the cost of removal factors is shown on Lines 18 and 19, applying the index ratios to the cost of removal factor on Line 10. The cost of removal factor of 193% shown on Line 19 is rounded to 190% in Column 6 of Schedule 5 of Petitioner's Exhibit DSR-2.

Q64. What is the Handy-Whitman Index of Public Utility Construction Costs?

(a) It is an index of public utility construction costs which has been published for many years by Whitman, Requardt and Associates of Baltimore, Maryland. It is composed of index numbers presented for various accounts prescribed by the Uniform System of Accounts promulgated by the Commission, and for a number of special subaccount categories of property usually occurring in "Building Construction," "Gas Plant Construction" and "Electric Light and Power Construction," for six geographical regions of the United States. Indiana is in the North Central Region, which comprises 12 states. These index numbers are computed by relating, for each year, the current prices for materials, labor and equipment to prices in a base year, which for most items is the year 1973. Current index numbers are determined and published for each year as of January 1 and July 1.

The index numbers I used are derived from the published indices. For each vintage, an average is produced as follows: the index number for January 1 is added to twice the July 1 index number, plus the index number for January 1 of the following year, and the sum of these four indices is then divided by four to arrive at an index applicable to construction occurring throughout the entire year. For years prior to 1974, the Whitman, Requardt publication shows annual indices and for later years shows January and July indices that I used to calculate annual indices.

DETAILS OF STUDY RESULTS

Q65. Please explain the results of your study of Steam Production Plant.

(a) For Steam Production Plant, the composite rate increased from 2.87% to 3.60%. The changes are caused by the combination of:

- Change in rate calculation procedure to recognize IPL's estimated generating unit life spans
- Recognition of future interim additions and retirements in rate calculations
- Decreased (more negative) terminal net salvage
- Segregation of interim net salvage

Column 6 of Schedule 2 of Petitioner's Exhibit DSR-2 shows the expected retirement dates used for calculating the depreciation rates. The terminal net salvage decreases (becomes more negative) for Steam Production Plant. The results are discussed in more detail on Pages 19 and 20 of Petitioner's Exhibit DSR-2.

Q66. Please explain the results of your study of Other Production Plant.

(a) The composite rate increased from 2.87% to 3.47%. The recommended rate for Stout recognizes the effect of combustion turbine units to be placed in service in 1994 and 1995. Column 6 of Schedule 2 of Petitioner's Exhibit DSR-2 shows the expected retirement dates used for calculating the depreciation rates. The terminal net salvage increases (becomes less negative). The existing rates indicate the Other Production Plant net salvage factors will be the same as for Steam Production Plant, whereas the TLG estimates show differences. The results are discussed in more detail on Page 20 of Petitioner's Exhibit DSR-2.

Q67. Please explain the results of your study of Transmission Plant.

(a) The composite rate increased from 2.42% to 3.56%. All but one of the five average service life changes are increases, and all of the seven net salvage changes are decreases (positive to negative or more negative). The results for each property group are discussed on Pages 20 through 24 of Petitioner's Exhibit DSR-2.

Q68. Please explain the results of your study of Electric Distribution Plant.

(a) The composite rate decreased from 5.11% to 4.68%. Of the 12 average service life changes, only three are decreases, and of the 12 net salvage changes, only four are increases (less negative). The results for each property group are discussed on Pages 24 through 30 of Petitioner's Exhibit DSR-2.

Q69. Please explain the results of your study of General Plant.

(a) The composite rate increased from 4.30% to 5.77%. Of the nine average service life changes, three are decreases, and of the four net salvage changes, two are increases. The results for each property group are discussed on Pages 30 through 33 of Petitioner's Exhibit DSR-2.

COMPARISON WITH DEPRECIATION RATES OF OTHER INDIANA ELECTRIC UTILITIES

Q70. How does the IPL composite rate of 3.96% resulting from your recommended rates compare to the composite rate which would result if the depreciation rates used by other Indiana electric utilities as of December 31, 1993, were applied to IPL's plant balances?

(a) The composite rates which would result are as follows:

Indiana Michigan Power Company (IMPCO)	4.32%
Northern Indiana Public Service Company (NIPSCO)	3.74%
PSI Energy	4.03%
Southern Indiana Gas and Electric Company (SIGECO)	3.90%

Q71. Please explain how you determined these comparative rates.

(a) These comparative composite rates were calculated by applying the account rates of the four companies to the IPL depreciable plant balances as of December 31, 1993, shown in Column 2 of Schedule 1 of Petitioner's Exhibit DSR-2, in order to eliminate differences due to investment mix. The calculations are shown on Petitioner's Exhibit DSR-8. The sources of the account rates for the other utilities are:

IMPCO - Company testimony in Cause No. 39314
NIPSCO - 1991 FERC Form No. 1 Report pages 337 and 338
PSI - Company testimony in Cause No. 37414-S2
SIGECO - 1992 FERC Form No. 1 Report page 337

For IMPCO and PSI, which use subaccounts different from those used by IPL, I used plant balances in the referenced testimony to calculate composites of certain of the rates needed for application to IPL property. For two to four accounts, depending on the company, I applied the IPL rate because the above sources did not list a rate for the property group. It should be pointed out, however, that depreciation rate differences among utilities can result from differences in rate calculation procedure and technique, the basis for determining the property mortality characteristics and whether they have embarked upon programs similar to IPL's unit optimization program.

Q72. **Are you familiar with the Commission's Order in Cause No. 39314 dated November 12, 1993, with regard to the approval of new depreciation rates for Indiana Michigan Power Company (IMPCO)?**

(a) Yes. I have reviewed the findings on the depreciation rate issues in that Order as well as the depreciation study submitted by IMPCO in that case and the testimony and exhibits relating thereto.

Q73. Does your study in this case use the same or similar methods used in IMPCO's study submitted in Cause No. 39314?

(a) Yes. That study also used the remaining life technique and life span forecast for Production Plant and the Average Life Group (ALG) procedure for Transmission, Distribution and General Plant.

Q74. Please explain how calculation procedures affect depreciation rates.

(a) The straight-line procedures are Units-of-Production, Equal Life Group (ELG) and ALG. Units-of-Production is based on life defined by usage and ELG and ALG are based on life defined by time. ELG recognizes that very few of the components of a depreciable property group will be retired at an age equal to the average service life of the group. ALG assumes that every component will be retired at an age equal to the average service life, but this does not actually occur. Therefore, ALG rates are usually lower than ELG rates, because of the deferral of recording depreciation that is inherent in ALG rates.

For example, the rates this Commission has authorized for the Transmission, Distribution and General Plant of PSI are ELG and for the other companies are ALG. In my study for IPL, I used ALG rates for this property.

Q75. Please explain how calculation techniques affect depreciation rates.

(a) The techniques are remaining life and whole life. Remaining life rates reflect the book reserve position and are calculated from future net salvage factors and remaining (future) lives. Whole life rates do not reflect the reserve position and are calculated from average net salvage factors and average service lives.

For example, the rates this Commission has authorized for the Transmission, Distribution and General Plant of PSI are whole life (with an added reserve difference adjustment amount). The rates this Commission has approved for IMPCO in Cause No. 39314 and for NIPSCO in Cause No. 38045 are remaining life. The rates I recommend for IPL are remaining life.

Q76. Please explain how the basis for determining mortality characteristics affects depreciation rates.

(a) Since the magnitude of rates partially depends on the mortality characteristics, differences in how such characteristics are determined translate into depreciation rate differences. An example is the basis for determining the terminal net salvage for power plants. IMPCO and PSI determined terminal net salvage for steam generating units from site-specific estimates, and NIPSCO and SIGECO have not prepared such estimates. My study for IPL incorporates the site-specific estimates prepared by TLG Services, Inc.

Q77. Please explain how programs such as IPL's unit optimization program affect depreciation rates.

(a) The effects of such programs depend on the relationship between the magnitude of the capital expenditures and the extra life resulting therefrom, and it is my experience that such programs usually increase depreciation rates. IPL has embarked upon a unit optimization program that has resulted in the expectation of 60-year operating life spans of Pritchard Units 3, 4, 5 and 6, and Stout Units 5 and 6, and the Company may eventually extend the program to Petersburg Units 1 through 4 and Stout Unit 7. PSI and IMPCO have embarked upon similar programs to increase the life spans of certain generating units through refurbishment, and their authorized depreciation rates for Steam Production Plant were determined in a manner quite similar to how I determined the rates I recommended for IPL.

Q78. In your opinion, should the depreciation rates resulting from your study be implemented by IPL?

(a) Yes, because the depreciation rates produce a reasonable and fair level of depreciation expenses, and were developed in compliance with accounting rules and regulatory principles.

Q79. Does this complete your prepared direct testimony?

(a) Yes, it does.

Academic Background

Donald S. Roff graduated from Rensselaer Polytechnic Institute with a Bachelor of Science degree in Management Engineering in 1972.

Mr. Roff has also received specialized training in the areas of depreciation from Western Michigan University's Institute of Technological Studies. This training involved three 40-hour seminars on depreciation entitled "Fundamentals of Depreciation," "Fundamentals of Service Life Forecasting" and "Making a Depreciation Study," and included such topics as accounting for depreciation, estimating service life, and estimating salvage and cost of removal.

Employment and Professional Experience

Following graduation from Rensselaer Polytechnic Institute, Mr. Roff was employed for 11-1/2 years by Gilbert Associates, Inc. as an engineer in the Management Consulting Division. In this capacity, he held positions of increasing responsibilities related to the conduct and preparation of various capital recovery and valuation assignments.

In 1984, Mr. Roff was employed by Ernst & Whinney and was involved in several depreciation rate studies and utility consulting engagements.

In 1985, Mr. Roff joined Deloitte Haskins & Sells (DH&S), which in 1989 merged with Touche Ross & Co. to form Deloitte & Touche.

During his tenures with Gilbert Associates, Inc., Ernst & Whinney, DH&S and Deloitte & Touche, Mr. Roff has participated in or directed depreciation studies for electric, gas, water and steam utilities, pipelines, railroad and telecommunications companies in over 30 states and several Canadian provinces. This work requires an in-depth knowledge of depreciation accounting and regulatory principles, mortality analysis techniques and financial practices.

At Gilbert Associates, Inc., Ernst & Whinney, DH&S and Deloitte & Touche, Mr. Roff has had varying degrees of responsibility for valuation studies, development of depreciation accrual rates, consultation on the unitization of utility property records, and other studies concerned with the inspection and appraisals of utility property, preparation of rate case testimony and support exhibits, data responses and rebuttal testimony.

Industry and Technical Association Affiliations

Mr. Roff is a registered Professional Engineer in Texas and Pennsylvania.

Mr. Roff is a member of the Society of Depreciation Professionals and a Technical Associate on the American Gas Association (A.G.A.) Depreciation Committee. He currently serves as the Chairman of the A.G.A. Depreciation Committee's Principles and Education Sub-Committee and is also the lead instructor for the A.G.A.'s Principles of Depreciation Course. He is a firm-designated Industry Specialist.

INDIANAPOLIS POWER & LIGHT COMPANY

Book Depreciation Study of Electric Utility Property as of December 31, 1993

September 1994

Indianapolis Power & Light Company
25 Monument Circle
Indianapolis, IN 46206

In accordance with your request and with the Company's continuing program of surveillance, we have conducted a book depreciation study of the Company's electric utility property. The purpose of the study was to determine if the existing functional composite depreciation rates remain appropriate for the Steam and Other Production, Transmission, Electric Distribution and General Plant, and if not, to recommend changes. Changes are recommended, and are needed in response to life changes that are predominantly increases (causing rate decreases) and net salvage changes that are almost all decreases (causing rate increases). In addition, we recommend that the Company adopt account rates for Steam and Other Production, Transmission, Electric Distribution and General Plant, rather than functional composite rates.

The comparisons presented herein include that portion of the Common Steam Production and General Plant used for electric operations. The recommended rate for Common Steam Production Plant is the same as the existing composite rate authorized through the settlement of Indiana Utility Regulatory Commission (I.U.R.C.) Cause No. 39440. The recommended rates for property other than Common Steam Production Plant result from the study reported herein. The study recognized historical addition and retirement experience through December 31, 1993, and the recommended account depreciation rates are calculated as of December 31, 1993.

A comparison of the effect of the recommended account rates with the existing functional composite rates is shown below:

Functional Group	Composite Rate Existing %	Composite Rate Resulting From Recommended Account Rates %
Steam Production Plant	2.87	3.59
Common Steam Production Plant	2.72	2.72
Other Production Plant	2.87	3.46
Transmission Plant	2.42	3.56
Electric Distribution Plant	5.11	4.68
General Plant	4.30	5.77
Total Electric Plant	3.45	3.95

The preceding summary is taken from Schedule 1, which shows the annual depreciation expense amounts for the existing and recommended rates and the differences. Based on the December 31, 1993, depreciable plant balances, the recommended rates would result in an annual increase in depreciation provisions of $11,016,074 (about 15 percent), as shown in Column 7 of Schedule 1. The existing rates other than for Common Steam Production Plant were authorized by the 1986 I.U.R.C. Order in Cause No. 37837.

Schedules 2, 3 and 4 show the mortality characteristics used to calculate the existing and the recommended rates. The mortality characteristics are (1) generating unit retirement dates or average service lives, (2) dispersion (variation) of retirements around average service life defined by either pending construction and interim addition and retirement ratios, or by Iowa-type dispersion patterns, and (3) salvage, cost of removal, net salvage factors or amounts. Schedule 2 shows the retirement dates, and Schedules 3 and 4 show the other mortality characteristics.

The generating unit retirement dates were provided by the Company. Certain future capital expenditures will be required for the units to reach their predicted retirement dates, most of which were included in the rate calculations, in order to be consistent with accounting principles. The need for this consistency and how it was accomplished are explained later in this report.

The primary reasons for the recommended changes to the Steam and Other Production Plant depreciation rates are the use of a rate calculation procedure reflecting direct recognition of certain future interim additions and all future interim retirements in rate calculations and the Company estimated generating unit life spans resulting therefrom, and a decrease (more negative) in terminal net salvage. The most significant change for Steam Production Plant was to net salvage and for Other Production Plant was to life.

The primary reason for the Transmission and Electric Distribution Plant changes is the net effect of increases in average service lives and decreases in net salvage factors (less positive or more negative). The primary reasons for General Plant are (1) the same as in the case of Transmission and Electric Distribution Plant and (2) a change in mix of the surviving assets.

The following sections of this report describe the methods of analysis used, the bases for the conclusions reached, and recommendations for both immediate and future action by the Company.

We appreciate this opportunity to serve the Indianapolis & Light Power Company, and would be pleased to meet with you to discuss further the matters presented in this report, if you desire.

Yours very truly,

PURPOSE OF DEPRECIATION ACCOUNTING

Book depreciation accounting is the process of recognizing in financial statements the investment related costs involved with the consumption of physical assets in the process of providing a service or a product. Generally accepted accounting principles require the recording of these costs through depreciation provisions to be systematic and rational. To be systematic and rational, depreciation should, to the extent possible, match either the consumption of the facilities or the revenues generated by the facilities. To ensure that financial statements reflect the result of operations and changes in financial position as accurately as possible, expenses should be matched with either asset consumption or revenues. The matching principle is often referred to as the *cause and effect* principle, thus, both the cause and the effect are required to be recognized for financial accounting purposes.

Since utility revenues are determined through regulation, asset consumption is not automatically reflected in revenues. Therefore, the consumption of utility assets must be measured directly by conducting a book depreciation study to accurately determine their mortality characteristics and to utilize these characteristics to calculate depreciation rates in a manner that is both systematic and rational.

The matching principle is also an element of the regulatory philosophy known as *intergenerational customer equity*. Intergenerational equity means the costs are borne by the generation of customers that caused them to be incurred, not by some earlier or later generation. This matching is intended to permit the fixing of charges to customers which reflect the actual costs of providing service.

This study was conducted in a manner that enhances the compliance of the results with the matching principles of accounting and regulation.

DEPRECIATION DEFINITIONS

The Uniform Systems of Accounts prescribed for electric utilities by the I.U.R.C., and followed by the Company states that:

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

"Service value" means the difference between original cost and net salvage value of electric plant.

"Net salvage value" means the salvage value of property retired less the cost of removal.

"Salvage value" means the amount received for the property retired less any expenses incurred in connection with the sale or in preparing the property for sale, or, if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate account.

"Cost of removal" means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto.

As is evident from the wording of the salvage value and cost of removal definitions, it is the salvage that will actually be received and the cost of removal that will actually be incurred, both as of the time of receipt or incurrence, that are required to be recognized in the depreciation rates of the Company.

These definitions are consistent with the purpose of depreciation, and the study reported here was conducted in a manner consistent with both.

ACCOMPLISHMENT OF MATCHING PRINCIPLES

The matching (cause and effect) principle has a significant influence on how a depreciation study of Steam and Other Production Plant is conducted. It is necessary to incorporate future interim additions into the calculation of Production Plant depreciation rates to comply with the matching principle and to have all components of the rate calculation consistent with each other, as the expected generating unit retirement dates cannot occur without the future additions occurring. Future interim retirements are included in an effort to ensure full recovery by the time the retirements occur. Handling future interim additions and retirements in this manner assures compliance with accounting principles, and promotes the recovery of capital from the customers actually served by the facilities.

A generating unit experiences capital additions and retirements over its life as items are replaced and items not originally required are added, and the unit is eventually retired. This addition and retirement activity is required to maintain the reliability of a generating unit, thus assuring that the originally planned operating life occurs. For example, a unit requiring replacement of condenser tubes would cease to function if replacement does not occur. Not making the replacement would cause the unit to be retired. Thus, if the tube replacement is expected to allow the unit to live another 10 years, the extra 10 years would be considered for calculating the depreciation rate, provided that both the retirement of the old tubes (interim retirement) and the addition of the new tubes (interim addition) were also recognized. If the addition of the new tubes is not considered, the shorter life to the time of replacement would be used for rate calculation. Thus, the interim additions and retirements are linked to the remaining life span.

The matching principle allows depreciation rates to be based on either elimination of both the interim power plant addition amounts and the extra generating unit life resulting therefrom or the inclusion of both, either of which will keep the rate calculation components consistent with each other. Inclusion of all future additions was adopted for Pritchard Units 1 through 6 and Stout Units 3 through 6, because definitive estimates of the expenditures and the life spans are available, and the life span estimates assume that the expenditures will be made. Exclusion of unit optimization program additions and the life spans resulting therefrom was selected for the Petersburg units and Stout Unit 7, because these units are not yet old enough for initiation of the equipment assessments needed to estimate the magnitude and timing of the expenditures and whether they will be justified.

This study recognizes the importance and influence of the interim additions and retirements planned for Pritchard Units 1 through 6 and Stout Units 3 through 6, which will make their predicted life spans possible. If recognition of the additions and retirements is instead deferred, but the different life spans they cause is used for depreciation rate calculations, the rates will initially decrease and then will increase at each recalculation. The initially lower depreciation expenses from deferral would cause a small decrease in near-term revenue requirements, but would increase the net original cost of the property reflected on the books of the Company. Deferring recognition of interim additions has a far greater impact on near-term and long-term revenue requirements than does deferring recognition of interim retirements. Deferral would also cause intergenerational inequity by requiring future customers to pay rates which include a disproportionate share of the costs of the plants.

Remaining life rates provide for full recording and recovery over the remaining life of surviving property, thus improving the match between actual property consumption and the recording of depreciation. Remaining life rates are also beneficial because they compensate for any past over or under accruals of depreciation and plant and reserve transactions different from those anticipated by the mortality characteristics used to calculate the existing rates, and limit depreciation recoveries to investment net of expected salvage and cost of removal - no more and no less.

Utility depreciation accounting is a group concept. Inherent in this concept is the assumption that all property is fully depreciated at the time of retirement, regardless of age, and there is no attempt to record the depreciation applicable to individual components of the property groups. The depreciation rates are based on the recognition that each depreciable property group has an average service life. However, very little of the property is *average*. The group concept carries with it recognition that most property will be retired at an age either less than or greater than the average service life, and will be fully depreciated at retirement, no matter at what age the retirement occurs. The study recognized the existence of this variation through the identification of Iowa-type retirement dispersion patterns for all property groups except Production Plant. Dispersion for Production Plant was recognized through the use of pending construction additions and interim addition and retirement ratios.

A life span depreciation rate calculation procedure was selected for Steam and Other Production Plant. The study developed Average Life Group (ALG) rates for Transmission, Electric Distribution and General Plant.

THE BOOK DEPRECIATION STUDY

Implementation of a policy toward book depreciation that recognizes the purpose of depreciation accounting requires the determination of mortality characteristics that are applicable to surviving property. The purpose of the depreciation study reported here was to accurately estimate those mortality characteristics, and to use the characteristics to determine appropriate rates for accrual of depreciation expenses.

The major effort of the study was the determination of the appropriate mortality characteristics. The remainder of this report describes how those characteristics were determined, compares the newly determined mortality characteristics with those used to calculate the existing rates, describes how the mortality characteristics were used to calculate the recommended depreciation rates, and presents the results of the rate calculations.

The study consisted of the following steps:

> Step One of the study was a Life Analysis consisting of determination of historical retirement experience and an evaluation of the applicability of that experience to surviving property. For Steam and Other Production Plant this step also entailed the determination of the generating unit retirement dates suitable for rate calculations.
>
> Step Two was a Salvage and Cost of Removal Analysis consisting of a study of salvage and cost of removal experience and an evaluation of the applicability of that experience to surviving property.

Step Three consisted of the determination of the generating unit remaining lives, the average service lives, the retirement dispersion identified by pending construction additions and interim addition and retirement ratios for Steam and Other Production Plant and by Iowa-type curves for the other property, and the future net salvage factors applicable to surviving property.

Step Four was the determination of the depreciation rate applicable to each depreciable property group, recognizing the results of the work in Steps One through Three.

LIFE ANALYSIS

The Life Analysis for the property concerns the determination of remaining life spans and interim addition and retirement ratios for Steam and Other Production Plant, and average service lives and Iowa-type retirement dispersion patterns for the other property. The Life Analysis for Production Plant consisted of both a forecast and an historical analysis, and for the other property consisted of an historical analysis.

Production Plant

The nature of Steam and Other Production Plant is such that the applicable average service life and dispersion pattern can be determined only after terminal retirements have taken place. Terminal retirements are comprised of those original additions and interim additions that survive to the end of the life of the unit. Without terminal retirements, any method of Life Analysis, including the actuarial method used for Transmission, Electric Distribution and General Plant, will usually indicate a higher average service life and less dispersion than is applicable to the property. Average service life will be accurately measured only when original and interim additions, and interim and terminal retirements are included.

For Production Plant, the Life Analysis required two steps. The first step was the estimation of the retirement date of each generating unit. The second step was the calculation of past interim addition and retirement ratios. The Company provided the estimated retirement date for each generating unit. The retirement dates utilized for rate calculations are shown in Column 6 of Schedule 2, in order to maintain the required link between future interim additions and the life spans of the units.

Interim addition and retirement ratios were determined from an analysis of actual Company experience conducted by plant and account, and separate ratios were determined for each Production Plant account. The interim addition analysis consisted of relating the sum of the past interim additions to the sum of the past interim retirements. The interim additions are expressed as a ratio of interim retirements, thus are the number of dollars of interim additions for each dollar of interim retirements. The interim retirement analysis consisted of relating the sum of the past interim retirements to the sum of the depreciable balances. When expressed as a percentage, the interim retirement ratio is the depreciation rate that would have recovered an amount equal to the total interim retirements.

Transmission, Electric Distribution, and General Plant

An analysis of historical retirement activity, suitably tempered by informed judgment as to the future applicability of such activity to surviving property, formed the basis for determination of average service lives and retirement dispersion patterns for the Transmission, Electric Distribution and General Plant property groups. For most accounts, retirement experience for 1966 through 1993, was analyzed using the actuarial method of Life Analysis.

The actuarial method determines actual survivor curves (observed life tables) for selected periods of actual retirement experience and was used because the vintage of the surviving property and of the retired property is known. In order to recognize trends in life characteristics and to assure that the valuable information in the curves is available to the analyst, observed life tables were calculated and plotted by computer using several different periods of retirement experience. The average service lives and retirement dispersion patterns indicated by these actual survivor curves were identified by visually fitting Iowa-type dispersion curves to the actual curves.

Trends in historical mortality experience are helpful in understanding history. In order to determine trends, the periods (year bands) of retirement experience analyzed were the past five, ten, 15 and 20 years and the total available experience, which for most of the property groups was since 1966. The observed life tables for these year bands and the Iowa curves fitted to each were plotted. This visual approach ensures that the data contained in the observed life tables and the trends are available to the analyst, and that the analyst does not allow computer calculations to be the sole determinant of study results.

The actuarial method of Life Analysis did not produce meaningful results for Production Plant, due to the lack of meaningful and significant terminal retirement experience. While the Company has terminal retirement experience for steam units (Stout Units 1 and 2), there is none for combustion turbine and diesel units. The retired Stout equipment has not been removed, and the plant still has operating units.

For property groups having little retirement experience or having retirement experience that is not an adequate indication of the expected mortality characteristics of surviving property, evaluation of the significance of history played a major role in selecting the mortality characteristics shown on Schedules 3 and 4. Examples of these evaluations and their effects are discussed later.

SALVAGE AND COST OF REMOVAL ANALYSIS

Salvage and cost of removal experience for 1979 through 1993 was the basis for determining the salvage, cost of removal and net salvage factors shown in Columns 8, 9 and 10 of Schedule 3 and in Columns 7, 8 and 9 of Schedule 4. The analysis was done in a manner that allows selection of separate salvage and cost of removal factors for most depreciable property groups. Net salvage is positive when salvage exceeds cost of removal, and is negative when cost of removal exceeds salvage.

Third-party and customer reimbursements for construction were segregated and related to additions, because the Company credits certain of them to retirement work orders. This procedure makes such reimbursements appear to be salvage, but they are actually payments related to the replacement property, so must be related to that property for the appropriate credit to be reflected in the depreciation rates. This segregation was available only for the period 1983 through 1993.

The analysis consisted of calculating the experienced salvage and cost of removal factors for each property group by dividing salvage and cost of removal amounts by the original cost of the retired property. Factors are expressed as percentages, and were calculated for annual, rolling, and shrinking bands of retirement experience. For most property groups the factors were plotted and the trends were illustrated by linear regression.

Net salvage factors are sensitive to the age of retired property. This phenomenon is important to this study, because of the nature of the Life and Salvage and Cost of Removal Analysis procedures utilized. The Life Analysis procedure determines the average service life applicable to original installations. The Salvage and Cost of Removal Analysis procedure determines the net salvage applicable to original installations only if the age of retirements is the same as the average service life. If the age of retirements is less than average service life, salvage factors will normally be overstated and cost of removal understated. If the age of retirements is greater than average service life, salvage factors will normally be understated and cost of removal factors overstated. When analysis of study data shows that this situation exists, some compensation is appropriate.

The average dollar age of retirements of Transmission and Electric Distribution Plant showed that an additional Salvage and Cost of Removal Analysis step was needed to estimate the future cost of removal that the Company's cost of removal experience indicates will result from the retirement of all surviving property. The analysis consisted of estimating the original cost amounts that would have been recorded during 1989 through 1993 if the actual retirements had been of an age equal to the expected age at which the property surviving at December 31, 1993 will be retired. Schedule 5, Column 2 shows the actual ages for the property groups needing this additional analysis and Column 4 shows the cost of removal factors experienced by the property. Column 3 shows the expected ages of the surviving property upon retirement and Column 6 shows the cost of removal factors that would have been experienced by the 1989 through 1993 retirements if they had been of the age shown in Column 3 rather than the age shown in Column 2.

The Company has relevant interim salvage and cost of removal experience for Production Plant, but not for terminal salvage and cost of removal. The interim salvage and cost of removal factors selected for Steam and Other Production Plant reflect actual experience. Terminal net salvage amounts based on dismantlement cost estimates prepared by TLG Services, Inc. (TLG) were used for Steam and Other Production Plant. The TLG estimates were converted to the anticipated cost levels at the time each plant is expected to be demolished.

As with the Life Analysis, the results of the Salvage and Cost of Removal Analysis were evaluated to the extent considered necessary to ensure applicability to the surviving property. The considerations were similar in nature to those applicable to the Life Analysis.

EVALUATION OF ACTUAL EXPERIENCE

Life Analysis and Salvage and Cost of Removal Analysis involve the measurement of what has occurred in the past. There are many kinds of events that can cause history to be an inappropriate indication of the future, among them changes in the underlying accounting procedures, changes in other management practices such as maintenance procedures, and types of activities not expected to continue or not to continue to the same degree. It is the evaluation phase of a depreciation study that identifies if history is a reasonable indication of the future. Blind acceptance of history often results in selecting mortality characteristics to use for calculating depreciation rates that will provide recovery over a time period longer than service life.

For Production Plant, part of the analysis process included historical addition and retirement experience. Since the magnitude of interim additions and retirements depends upon plant maturity, the analyses were conducted in a manner that allows the influence of unit age to be reflected in the conclusions drawn from the analysis. This was accomplished by utilizing the entire history and by conducting the analyses by account and by generating plant.

The actuarial method of Life Analysis used for Transmission, Electric Distribution and General Plant was not adopted for Production Plant, because the Company's terminal retirement experience is insufficient for steam generating units and because there is no terminal retirement experience for combustion turbine and diesel units.

For Transmission, Electric Distribution, and General Plant, the analysis processes involved only historical retirement experience. Since the depreciation rates will be applied to surviving property, the historical mortality experience indicated by the Life and the Salvage and Cost of Removal Analyses was evaluated to ensure that the mortality characteristics used to calculate the rates are applicable to surviving property. The evaluation is required to assure the validity of the recommended depreciation rates.

The evaluation process requires knowledge of the type of property surviving, the type of property retired, the reasons for changing life, dispersion, salvage, and cost of removal, and the effect of present and future Company plans on the property mortality characteristics. The evaluation included discussions with Company accounting, engineering, and operating personnel, determination of the type of property recorded in a number of accounts, and special analyses of retirements to identify the type of property retired and reasons for retirement.

The decreases in net salvage for Transmission and Electric Distribution Plant are caused, at least in part, by increases in the age of retired property that caused the average service lives to increase. This phenomenon is important to this study, because of the nature of the Life and Salvage and Cost of Removal Analysis procedures that was explained earlier and certain Company accounting practices.

The analyses of several Transmission and Electric Distribution Plant property groups are influenced by the Company's practice of determining the vintage of some retired property on a first-in-first-out basis. This causes dispersion patterns to be narrow and the actual age of reused materials to be less than the age of retirement amounts. This situation improves the applicability of cost of removal factors to surviving property, because the average dollar age of retirement amounts is closer to the expected average age of surviving property upon retirement. However, it reduces the applicability of salvage ratios, because a larger portion of the retired items will be salvaged and reused than the portion suggested by the high average dollar age of retirement amounts. In view of the large changes found needed for Transmission and Electric Distribution Plant net salvage factors, no salvage factor adjustments were made for this situation, which if made would have further increased the depreciation rates. However, the cost of removal factors selected for some of these property groups reflect the small cost of removal adjustments shown in Column 8 of Schedule 5. The property groups to which this situation applies are indicated in the later discussions of the bases for selecting the salvage and cost of removal factors.

The retirements of some Transmission and Electric Distribution Plant property groups were found to be young relative to average service life, due to the Company's practice of determining the vintage of some retired property from construction records. This results in overstating the salvage factors and understating the cost of removal factors applicable to surviving property, if history serves as the sole basis for net salvage determination. Salvage factors are overstated because young property is more likely to be reused than junked and the salvage value of reused items is much higher than the scrap value. Cost of removal factors are understated, because the amount of cost escalation reflected in the cost to remove or safely abandon young property is less than the amount that will be reflected in the cost to remove the surviving property at a higher age. The average age of original installations at retirement is equal to the average service life, meaning that the average age of surviving property at retirement will be higher than the average service life, and much higher than the age of current retirements. The cost of removal factors selected for these property groups reflect the cost of removal increases shown in Column 8 of Schedule 5 made as a small step toward recognizing this situation in the depreciation rates.

CALCULATION OF DEPRECIATION RATES

A straight-line remaining life rate for each depreciable property group was calculated using the following formula:

$$\text{Rate} = \frac{\text{Plant Balance - Future Net Salvage - Book Reserve}}{\text{Average Remaining Life}}$$

This formula illustrates that a remaining life rate is future oriented and recognizes the book reserve position. The actual calculations utilize dollar amount numerator elements with conversion to a percentage rate as the last step of the calculation process.

The remaining life depreciation rates for Production Plant were calculated that would cause the book reserve for each property group to become zero at the time of the retirement of the last generating unit. Future interim additions and retirements indicated by the historical analysis and pending construction, net salvage for interim retirements, and net salvage for terminal retirements were reflected in the rate calculations. Future interim additions were recognized in the depreciation rate calculations for Pritchard Units 1 through 6 and Stout Units 3 through 6, in conjunction with the use of 60-year life spans. Since the future interim additions are necessary to obtain a 60-year life, the matching principle requires consideration of both at the same time.

Schedule 6 utilizes Stout Account 312.1 to demonstrate how the formula was used to calculate a remaining life rate for each plant and account that is intended to cause full recovery at the time the last generating unit is retired. The future interim addition and retirement amounts and the terminal retirement amounts are calculated for each generating unit on Pages 1 and 2 from the pending construction expenditures, the interim addition and retirement ratios shown in Columns 6 and 7 of Schedule 3, the remaining life span of each individual generating unit determined from the retirement date shown in Column 6 of Schedule 2, and the December 31, 1993 depreciable plant balances. The rate calculation is shown on Page 3 of Schedule 6, and uses the annual interim addition and retirement amounts and plant balances calculated on Pages 1 and 2. The depreciable plant and book reserve balances are from Company accounting records, the interim net salvage factors were determined by the study, and the terminal net salvage amounts were determined from the TLG estimates.

For Transmission, Electric Distribution, and General Plant, the depreciable plant and book reserve balance for each property group are from Company accounting records. The average remaining lives were calculated from the average service life and dispersion pattern determined by the study and the age distribution of each surviving property group determined from Company property records. The future net salvage factors were determined by the study.

RESULTS

The interim addition and retirement ratios, interim net salvage factors and retirement dates used to determine the remaining life spans used to calculate the recommended Steam and Other Production Plant rates are shown on Schedules 2 and 3. The mortality characteristics for the existing rates are also shown on Schedule 3 for comparison purposes.

The average service life, retirement dispersion pattern, salvage factor, cost of removal factor and net salvage factor used to calculate each recommended rate for Transmission, Electric Distribution, and General Plant are shown on Schedule 4. For comparison purposes, the same data are shown for each existing rate. However, the salvage and cost of removal factors reflected in the existing net salvage factors are unknown. For most property groups, changes to mortality characteristics follow the trends indicated by the recent retirement experience. This was the retirement experience of the past ten to 15 years for the Life Analysis and the past five to ten years for the Salvage and Cost of Removal Analysis. Life changes are mostly increases, and net salvage changes are mostly decreases.

The second step of the Salvage and Cost of Removal Analysis described on Page 13 identified the future cost of removal factors needed to calculate remaining life rates for certain Transmission and Electric Distribution Plant property groups. In view of the large rate increases that would result from incorporating the future cost of removal factors into the rate calculations, the recommended rates reflect only the small step toward these future factors that is determined on Schedule 5. Column 7 of Schedule 5 shows the percentage point difference between cost of removal factors based on history (Column 5) and the indicated future cost of removal factors (Column 6). Column 8 shows the cost of removal adjustments selected, which are zero for differences less than 10%, 5% changes for differences of 10% to 50%, 10% changes for differences of 50% to 100%, 15% changes for differences of 100% to 150% and 20% changes for differences over 150%.

Based on December 31, 1993, depreciable balances, the overall composite rate increased from 3.45% to 3.95%. Reasons for the changes are discussed below.

Steam Production Plant

The composite rate increased from 2.87% to 3.59%. Schedule 2 shows the year of commercial operation and the estimated year of retirement of each existing generating unit that was used for rate calculation purposes.

The actuarial method of Life Analysis will overstate the average service life when terminal retirements are lacking. While the Company has terminal retirement experience for steam generating units, the actuarial method was not used, because terminal retirement experience is insufficient to produce meaningful results. Therefore, the recommended rate for each plant and account was calculated using the procedure illustrated on Schedule 6.

The pending construction through 1995 and future interim additions beyond 1995 calculated from interim addition ratios were included in the rate calculations for Pritchard Units 1 through 6 and Stout Units 3 through 6, because the generating unit retirement dates assume that those expenditures will be made. Sixty-year life spans were selected for Petersburg Units 1 and 2, in view of the recent Commission authorization for the Company to proceed with adding a scrubber to these units. All future interim retirements were included to ensure that they are fully depreciated by the time they occur. The interim retirement ratios were applied to beginning of year plant balances to estimate the interim retirement amounts for all years.

The interim net salvage factors are based on Company experience. The terminal net salvage is based on the TLG estimates escalated to the anticipated price levels at the time dismantlement is expected. Their large boilers, fuel handling equipment, and ash disposal systems make coal units expensive to remove, because of the extensive facilities that must be removed and because waste materials must be handled. All active units and the retired but not yet removed units at Stout have suspended boilers that are expensive to remove because of their design. In addition, all plants contain asbestos insulation that is expensive to remove and dispose of, some of which will remain until dismantlement.

Other Production Plant

The composite rate increased from 2.87% to 3.46%. The actuarial method of Life Analysis will overstate the average service life when terminal retirements are lacking, and the Company has no terminal retirement experience for combustion turbine and diesel units. Therefore, the recommended rate for each plant was calculated using the procedure illustrated on Schedule 6.

The retirement dates were provided by the Company. The pending construction through 1995 (including Stout Combustion Turbine Units 4 and 5 to be placed in service in 1994 and 1995), interim additions beyond 1995 calculated from interim addition ratios, and interim retirements for all years calculated from interim retirement ratios were incorporated into the rate calculations, because the retirement dates assume that those expenditures will be made. All future interim retirements were included with the intention of allowing them to be fully depreciated by the time they occur.

The interim net salvage factors are also based on Company experience, and the terminal net salvage is also based on TLG estimates.

Transmission Plant

The composite rate increased from 2.42% to 3.56%. All but one of the five average service life changes are increases, and all of the seven net salvage factor changes are decreases (positive to negative or negative to more negative). Greatest weight was given to recent experience by moving toward indicated trends. The magnitude of the rate increase was limited by the Company decision to use ALG rates for this functional group at this time and by our previously discussed decisions not to adjust salvage factors to reflect a lesser extent of material reuse in the future and to take only a small step toward the future cost of removal factors indicated by Company retirement experience.

Account 350.2, Land Rights

There has been little retirement experience. Use of an average service life ten years longer than the associated overhead lines is appropriate, in expectation that some rights-of-way will be reused.

The nature of the property will preclude salvage and cost of removal, so the use of zero for both is appropriate.

Account 352, Structures and Improvements

There has been limited retirement experience and as a result, the survivor curves are not well defined. No change in average service life is recommended, and is based on a weighting of the expected lives of the mix of surviving assets.

Retirements are young relative to the average service life, indicating that salvage and cost of removal experience presents a misleading indication of what is appropriate for surviving property. However, this experience is for remodeling and expansion, so overstates the cost of removal factors that can be expected upon complete dismantlement and site restoration. Therefore, the salvage and cost of removal selections for Account 390 were adopted, as they better recognize what can be expected upon complete dismantlement and site restoration.

Account 353, Station Equipment

The Life Analysis suggests that an increase in life would be appropriate. While there have been terminal retirements of major equipment, they have been limited. The closer design and manufacturing tolerances inherent in newer power transformers and circuit breakers are expected to cause them to have a shorter life than older units that could more easily withstand severe operating conditions. A modest increase in average service life is recommended. The selected dispersion pattern is based on the indications of the ten and 15 year experience bands.

Retirements are young relative to the average service life, indicating that salvage and cost of removal experience does not represent what can be expected from the surviving property. For the reason discussed previously, no adjustment was made to the salvage factor for this situation or for the fact that past salvage from reuse has been higher than can be expected from the surviving property. As is shown by Column 8 of Schedule 5, the cost of removal factor was increased by 5% to compensate for the effect of the young retirements. Terminal salvage will be limited and negative 10% net salvage was selected, based on 10% salvage and 20% cost of removal.

Account 354, Towers and Fixtures

Retirement experience has been limited and sporadic. The dispersion selection was based on the retirement experience from all bands, which indicates the Iowa R4 dispersion pattern. An increase in average service life to 50 years was adopted, based on Company expectations.

The salvage and cost of removal analyses results are influenced by some line rearrangements. Retirements are young relative to the average service life, indicating that salvage and cost of removal experience does not represent what can be expected from the surviving property. For the reason discussed previously, no adjustment was made to the salvage factor for this situation or for the fact that past salvage from reuse has been higher than can be expected from the surviving property. As is shown by Column 8 of Schedule 5, the cost of removal factor was increased by 20% to compensate for the effect of young retirements. Cost of removal is expected to substantially exceed salvage, resulting in negative 95% net salvage, composed of 25% salvage and 120% cost of removal.

Account 355, Poles and Fixtures

Fairly consistent results were obtained and an increase in average service life to 33 years and a shift in dispersion to S4 are recommended based on recent experience.

Retirements are slightly younger than the average service life, indicating that salvage and cost of removal experience does not represent what can be expected from the surviving property. However, the difference is insufficient to warrant adjustment to either salvage or cost of removal. Cost of removal exceeds salvage, particularly in recent years. A net salvage factor of negative 60% was selected, composed of 50% salvage and 110% cost of removal.

Account 356, Overhead Conductors and Devices

Consistent indications were obtained from the Life Analysis, showing a life increase. Based upon Company expectations and the analysis results, an average service life of 40 years and the R4 dispersion were selected.

Retirements are young relative to the average service life, indicating that salvage and cost of removal experience does not represent what can be expected from the surviving property. For the reason discussed previously, no adjustment was made to the salvage factor for this situation or for the fact that past salvage from reuse has been higher than can be expected from the surviving property. As is shown by Column 8 of Schedule 5, the cost of removal factor was increased by 10% to compensate for the effect of young retirements. The results are influenced by the 1989 sale of scrap material which was discounted. Cost of removal is expected to exceed salvage and a negative 60% net salvage was selected, composed of 70% salvage and 130% cost of removal.

Account 357, Underground Conduit

There has been limited retirement experience. Company expectations are an average life of at least 35 years, so the existing R3 dispersion pattern with an average service life of 40 years were retained.

Retirements are young relative to the average service life, indicating that salvage and cost of removal experience does not represent what can be expected from the surviving property. For the reason discussed earlier, no adjustment was made to the salvage factor for this situation or for the fact that past salvage from reuse has been higher than can be expected from the surviving property. There is insufficient cost of removal experience to warrant a cost of removal factor adjustment to compensate for this situation. Net salvage is expected to be negative 15%, composed of zero salvage and 15% cost of removal.

Account 358, Underground Conductors and Devices

There has been limited retirement experience and the average service life should be less than that of Account 357. An average service life is 35 years with an S0 dispersion pattern were adopted.

Retirements are young relative to the average service life, indicating that salvage and cost of removal experience does not represent what can be expected from the surviving property. For the reason discussed earlier, no adjustment was made to the salvage factor for this situation or for the fact that past salvage from reuse has been higher than can be expected from the surviving property. As is shown by Column 8 of Schedule 5, the cost of removal factor was increased by 5% to compensate for the effect of young retirements. Cost of removal is expected to exceed salvage and is reflected in our selection of negative 45% net salvage, composed of zero salvage and 45% cost of removal.

Distribution Plant

The composite rate decreased from 5.11% to 4.68%. Of the 12 average service life changes, only three are decreases. Of the 12 net salvage changes, only four are increases (less negative). Greatest weight was given to recent experience by moving toward indicated trends. The magnitude of the rate increase was limited by the Company decision to use ALG rates for this functional group at this time and by our previously discussed decisions not to adjust salvage factors to reflect a lesser extent of material reuse in the future and to take only a small step toward the future cost of removal factors indicated by Company retirement experience.

Account 360.2, Land Rights

There has been limited retirement experience. Use of a life ten years longer than the mix of the associated equipment is appropriate.

The nature of the property will preclude salvage and cost of removal, so use of zero for both is appropriate.

Account 361, Structures and Improvements

There has been adequate retirement experience, but the tail of the survivor curve is not well defined. A movement toward the indicated life is appropriate.

Cost of removal exceeds salvage in every year. Retirements are young relative to the average service life, indicating that salvage and cost of removal experience does not represent what can be expected from the surviving property. However, this experience is for remodeling and expansion, so overstates the cost of removal factors that can be expected upon complete dismantlement and site restoration. Therefore, the salvage and cost of removal selections for Account 390 were adopted, as they better recognize what can be expected upon complete dismantlement and site restoration.

Account 362, Station Equipment

The Life Analysis suggests that an increase in life would be appropriate. However, the closer design and manufacturing tolerances inherent in newer power transformers and circuit breakers is expected to cause them to have a shorter life than older units that could more easily withstand severe operating conditions. An increase in average service life to 40 years is recommended. The dispersion was adopted from the analysis indications, primarily from the longer experience bands.

Retirements are young relative to the average service life, indicating that salvage and cost of removal experience does not represent what can be expected from the surviving property. For the reason discussed earlier, no adjustment was made to the salvage factor for this situation or for the fact that past salvage reuse has been higher than can be expected from the surviving property. As is shown by Column 8 of Schedule 5, the cost of removal factor was increased by 5% to compensate for the effect of young retirements. Fifteen percent salvage and 25% cost of removal were selected.

Account 364, Poles, Towers and Fixtures

The analysis indications are influenced by the Company practice of first-in-first-out aging of retirements. An increase in average service life to 30 years is recommended with an S5 pattern.

Retirements are slightly older than the average service life, but salvage is overstated due to reuse. Again, for the reason discussed earlier, no adjustment was made to the salvage factor for this situation. As is shown by Column 8 of Schedule 5, the cost of removal factor was decreased by 5% to compensate for the effect of the old retirements. Cost of removal substantially exceeds salvage, and the net salvage selection of negative 135% reflects this situation, composed of 60% salvage and 195% cost of removal.

Account 365, Overhead Conductors and Devices

The analysis indications are influenced by the Company practice of first-in-first-out aging of retirements. An average service life of 30 years with an S5 pattern were selected.

Retirements are slightly older than the average service life, but salvage is overstated due to reuse. No adjustment was made for this situation to either salvage or cost of removal. Approximately ten percent of surviving conductor by weight is copper, so high salvage can be expected to continue. The net salvage selection of negative 120% is based on recent analysis indications, and is composed of 60% salvage and 180% cost of removal.

Account 366, Underground Conduit

A slight increase in average service life is indicated and is recommended, based upon the analysis results.

Retirements are young relative to the average service life, indicating that salvage and cost of removal experience does not represent what can be expected from the surviving property. For the reason discussed earlier, no adjustment was made to the salvage factor for this situation or for the fact that past salvage from reuse has been higher than can be expected from the surviving property. As is shown by Column 8 of Schedule 5, the cost of removal factor was increased by 15% to compensate for the effect of young retirements. Net salvage of negative 85% was selected, composed of 20% salvage and 105% cost of removal.

Account 367, Underground Conductors and Devices

The analysis indications are influenced by the Company practice of first-in-first-out aging of retirements. Consistent results support the existing average service life with a shift in dispersion pattern to S5.

Retirements are not as old as the average service life, indicating that salvage and cost of removal experience does not represent what can be expected from the surviving property. For the reason discussed earlier, no adjustment was made to the salvage factor for this situation or for the fact that past salvage from reuse has been higher than can be expected from the surviving property. As is shown by Column 8 of Schedule 5, the cost of removal factor was not adjusted to compensate for the effect of young retirements. Salvage is limited and cost of removal exceeds salvage. Our selection is negative 5% net salvage, comprised of 45% salvage and 50% cost of removal.

Account 368, Line Transformers

The Life Analysis indicates an increase in average service life, which is reflected in our selection.

The age of retirements is about half of the selected average service life, but history indicates little difference between experienced cost of removal and future cost of removal. Therefore, salvage and cost of removal experience represents what can be expected from the surviving property, and there is little reuse. High cost of removal was experienced during the period 1984 through 1988, due to the PCB removal program. This process is essentially complete and its effect was eliminated by basing selections on more recent experience. Salvage of 10% and cost of removal of 15% were selected.

Account 369.1, Overhead Services

The existing average service life and dispersion are for total Account 369. The analysis indications are influenced by the Company practice of first-in-first-out aging of retirements. This is a mature property group due to the demand and requirement for underground facilities. The average service life and dispersion pattern were based on the longer experience band indications.

Retirements are not as old as the average service life, but salvage is overstated due to reuse. For the reason discussed earlier, no adjustment was made to the salvage factor for this situation or for the fact that past salvage from reuse has been higher than can be expected from the surviving property. As is shown by Column 8 of Schedule 5, the cost of removal factor was increased by 5% to compensate for the effect of young retirements. Sixty-five percent salvage and 155% cost of removal were selected.

Account 369.2 Underground Services

The analysis indications are influenced by the Company practice of first-in-first-out aging of retirements. A decrease in average service life is appropriate based upon the majority of the analysis indications and the type of equipment, and because the existing average service life is for total Account 369.

Retirements are almost as old as the average service life, but salvage is overstated due to reuse. For the reason discussed earlier, no adjustment was made to the salvage factor for this situation or for the fact that past salvage from reuse has been higher than can be expected from the surviving property. As is shown by Column 8 of Schedule 5, the cost of removal factor was increased by 5% to compensate for the retirements not being quite as old as the average service life. Twenty percent salvage and 85% cost of removal were selected.

Account 370, Meters

The Life Analysis indicates a slightly decreasing average service life, which was responded to by decreasing the life from 34 years to 30 years.

While retirements are young relative to average service life, lack of salvage and cost of removal makes this situation meaningless. Zero salvage and cost of removal are appropriate.

Account 371, Installations on Customers' Premises

The property is automatic protective lighting located at customer sites. The analysis indications are influenced by the Company practice of first-in-first-out aging of retirements. The Life Analysis indicates a longer average service life than presently in use and was adopted.

Retirements are nearly as old as the average service life, but salvage is overstated due to reuse. For the reason discussed earlier, no adjustment was made for this situation. Cost of removal exceeds salvage by a wide margin. The selection is negative 45% net salvage, comprised of 40% salvage and 85% cost of removal.

Account 373, Street Lighting and Signal Systems

The analysis indications are influenced by the Company practice of first-in-first-out aging of retirements. A slight increase in average service life was adopted.

Retirements are nearly as old as the average service life, but salvage is overstated due to reuse. For the reason discussed earlier, no adjustment was made for this situation. Cost of removal substantially exceeds salvage and is reflected in the selection of a negative 30% net salvage figure, composed of 20% salvage and 50% cost of removal.

<u>General Plant</u>

The composite rate increased from 4.30% to 5.77%. Of the nine average service life changes, three are decreases, and of the four net salvage factor changes, two are increases. About half of the composite depreciation rate increase is due to a change in the mix of the surviving assets. The magnitude of the rate increase was limited through the Company decision to use ALG rates for this functional group at this time.

Account 390, Structures and Improvements

The account exhibits an increase in average service life, due to the relative mix of surviving assets. The selected average service life of 45 years is based upon a weighting of the expected lives of the individual components.

Retirements are young relative to the average service life, indicating that salvage and cost of removal experience presents a misleading indication of what is appropriate for surviving property. However, this experience is for remodeling and expansion, so exhibits higher cost of removal factors than can be expected upon complete dismantlement and site restoration. Therefore, the existing net salvage was not changed. A net salvage allowance of negative 20% is selected, composed of 5% salvage and 25% cost of removal.

Account 391.1, Office Furniture and Equipment

The property group exhibits an increasing average service life, which is reflected in the selection of an L0 pattern with an average service life of 25 years.

Net salvage of positive 5% was adopted in recognition of past experience, composed of 5% salvage and zero cost of removal.

Account 391.2, Computer Equipment

An average service life of eight years was selected, based upon the analysis indications and the type of surviving assets.

There has been some salvage and salvage is expected for retirements at an age equal to average service life. Very little cost of removal has been experienced, and our recommendation is positive 5% net salvage, composed of 5% salvage and zero cost of removal.

Account 392, Transportation Equipment

A life decrease is recommended based upon recent experience and the mix of surviving assets. The selected curve is S1 with an average service life of nine years.

Salvage exceeds cost of removal, reflecting trade-in allowances. We recommend positive 25% net salvage, composed of 25% salvage and zero cost of removal.

Account 393, Stores Equipment

The retirement experience indicates an increase in average service life. The primary assets are shelves and bins, and a longer life is appropriate, which is reflected in the selection of an L1.5 pattern with an average service life of 30 years.

While some cost of removal has been experienced in recent years, positive 10% net salvage is recommended, based on 10% salvage and zero cost of removal.

Account 394, Tools, Shop and Garage Equipment

The Life Analysis reveals increasing average service life, and the increase from 25 years to 28 years is a step toward the indicated trend.

Experience supports some salvage, and our selection is positive 10% net salvage, based on 10% salvage and zero cost of removal.

Account 395, Laboratory Equipment

The account indicates a modest increase in life and the selection of 28 years reflects this situation.

Salvage and cost of removal have been limited, and zero net salvage is appropriate, based on zero salvage and cost of removal.

Account 396, Power Operated Equipment

The majority of equipment is air tools and power equipment. A small decrease in average service life is appropriate, based upon the consistent life analysis indications. The selections are an average service life of 15 years and L0.5 dispersion.

Salvage has been diminishing and our selection of positive 20% net salvage, based on 20% salvage and zero cost of removal, reflects this trend.

Account 397, Communication Equipment

Major portions of this account are radio equipment. A downward life adjustment is appropriate and is supported by the life analysis indications. The selected curve is L2 with an average service life of 12 years.

The salvage and cost of removal experience is reasonable for the mix of surviving property. The selections are 5% salvage and 5% cost of removal, producing zero net salvage.

Account 398, Miscellaneous Equipment

Life Analysis indicate an increase in average life is appropriate. The selections are an S1 pattern and an average service life of 33 years.

Very little cost of removal or salvage has been incurred. Zero net salvage is appropriate, based on zero salvage and cost of removal.

RECOMMENDATIONS

The annual depreciation rates shown in Column 5 of Schedule 1 for each account are applicable to the existing property and we recommend their implementation at such time as the I.U.R.C. allows their effect to be incorporated into service rates.

Schedule 1
Page 1 of 2

INDIANAPOLIS POWER & LIGHT COMPANY
Comparison of Existing and Recommended Rates

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	12-31-1993	Existing Rates		Recommended Rates		
Functional Group and Account	Depreciable Balance	Rate	Annual Amount	Rate	Annual Amount	Increase or (Decrease)
	$	%	$	%	$	$
STEAM PRODUCTION PLANT						
E. W. Stout Plant						
310.2 Land Rights	194			3.64	7	
311 Structures & Improvements	29,155,499			4.50	1,311,997	
312.1 Boiler Plant Equipment	91,059,922			5.51	5,017,402	
312.2 Coal & Ash Handling Equipment	17,363,147			5.20	902,884	
314 Turbogenerator Units	37,936,351			4.63	1,756,453	
315 Accessory Electric Equipment	12,616,165			3.99	503,385	
316 Miscellaneous Power Plant Equipment	3,533,183			4.73	167,120	
Total E. W. Stout Plant	191,664,461			5.04	9,659,248	
H. T. Pritchard Plant						
311 Structures & Improvements	15,358,485			5.45	837,037	
312.1 Boiler Plant Equipment	47,416,599			6.78	3,214,845	
312.2 Coal & Ash Handling Equipment	9,058,752			6.03	546,243	
314 Turbogenerator Units	23,398,549			5.21	1,219,064	
315 Accessory Electric Equipment	6,581,293			5.19	341,569	
316 Miscellaneous Power Plant Equipment	1,183,322			6.24	73,839	
Total H. T. Pritchard Plant	102,997,000			6.05	6,232,597	
Petersburg Plant						
311 Structures & Improvements	133,726,316			3.04	4,065,280	
312.1 Boiler Plant Equipment	559,968,338			3.20	17,918,987	
312.2 Coal & Ash Handling Equipment	85,254,942			3.11	2,651,429	
314 Turbogenerator Units	135,491,249			2.84	3,847,951	
315 Accessory Electric Equipment	85,992,470			2.64	2,270,201	
316 Miscellaneous Power Plant Equipment	13,507,105			2.72	367,393	
Total Petersburg Plant	1,013,940,420			3.07	31,121,241	
Total Steam Production Plant	1,308,601,881	2.87	37,556,874	3.59	47,013,086	9,456,212
COMMON STEAM PRODUCTION PLANT						
Total	55,809,069					
Steam Heat Operations @ 76.9%	(42,917,174)					
Electric Operations	12,891,895	2.72	350,660	2.72	350,660	0
OTHER PRODUCTION PLANT						
344 Generators						
E. W. Stout Plant	7,005,488			3.34	233,983	
H. T. Pritchard Plant	213,347			3.39	7,232	
Petersburg Plant	684,269			4.74	32,434	
Total Other Production Plant	7,903,104	2.87	226,819	3.46	273,649	46,830

Schedule 1
Page 2 of 2

INDIANAPOLIS POWER & LIGHT COMPANY
Comparison of Existing and Recommended Rates

(1)		(2)	(3)	(4)	(5)	(6)	(7)
		12-31-1993	Existing Rates		Recommended Rates		
Functional Group and Account		Depreciable Balance	Rate	Annual Amount	Rate	Annual Amount	Increase or (Decrease)
		$	%	$	%	$	$
TRANSMISSION PLANT							
350.2	Land Rights	16,705,216			1.84	307,376	
352	Structures & Improvements	3,280,855			2.39	78,412	
353	Station Equipment	94,852,100			2.63	2,494,610	
354	Towers & Fixtures	38,730,666			4.42	1,711,895	
355	Poles & Fixtures	18,841,350			6.52	1,228,456	
356	Overhead Conductors & Devices	41,709,358			4.30	1,793,502	
357	Underground Conduit	1,309,108			2.76	36,131	
358	Underground Conductors & Devices	1,511,943			4.28	64,711	
	Total Transmission Plant	216,940,596	2.42	5,249,962	3.56	7,715,093	2,465,131
ELECTRIC DISTRIBUTION PLANT							
360.2	Land Rights	187,470			2.91	5,455	
361	Structures & Improvements	5,106,974			2.42	123,589	
362	Station Equipment	89,866,244			2.55	2,291,589	
364	Poles, Towers & Fixtures	52,168,893			8.89	4,637,815	
365	Overhead Conductors & Devices	61,353,152			8.11	4,975,741	
366	Underground Conduit	33,086,052			4.30	1,422,700	
367	Underground Conductors & Devices	73,009,862			4.23	3,088,317	
368	Line Transformers	101,413,001			1.83	1,855,858	
369.1	Overhead Services	19,547,304			5.88	1,149,381	
369.2	Underground Services	25,053,873			6.93	1,736,233	
370	Meters	38,716,442			3.72	1,440,252	
371	Installations on Customers' Premises	16,531,744			8.84	1,461,406	
373	Street Lighting & Signal Systems	32,940,900			4.57	1,505,399	
	Total Distribution Plant	548,981,911	5.11	28,052,976	4.68	25,693,735	(2,359,241)
GENERAL PLANT							
390	Structures & Improvements	41,226,138			2.69	1,108,983	
391.1	Office Furniture & Fixtures	6,978,983			3.36	234,494	
391.2	Computer Equipment	11,748,644			11.85	1,392,214	
392	Transportation Equipment	15,294,901			11.77	1,800,210	
393	Stores Equipment	1,033,840			2.66	27,500	
394	Tools, Shop & Garage Equipment	8,786,755			2.92	256,573	
395	Laboratory Equipment	4,674,502			3.40	158,933	
396	Power Operated Equipment	2,194,637			6.84	150,113	
397	Communication Equipment	4,375,021			10.70	468,127	
398	Miscellaneous Equipment	1,278,111			2.75	35,148	
	Total General Plant	97,591,532			5.77	5,632,295	
	Steam Heat Operations @ 2.0%	(1,951,831)			5.77	(112,646)	
	Electric Operations	95,639,701	4.30	4,112,507	5.77	5,519,649	1,407,142
	Total Electric Plant	2,190,959,088	3.45	75,549,798	3.95	86,565,872	11,016,074

INDIANAPOLIS POWER & LIGHT COMPANY **SCHEDULE 2**

Generating Unit Retirement Dates

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Summer		Year	Year Retired		Total
Station & Unit	Capability	Fuel	Installed	Planned	Study	Life
	kW					years
STEAM PRODUCTION PLANT						
E. W. Stout Plant						
Unit 1 (a)	36,750	Oil	1931			56
Unit 2 (a)	36,750	Oil	1931			56
Unit 3	35,000	Oil	1941	2001	2001	60
Unit 4	35,000	Oil	1947	2007	2007	60
Unit 5	106,000	Coal	1958	2018	2018	60
Unit 6	106,000	Coal	1961	2021	2021	60
Unit 7	422,000	Coal	1973	2033	2013	40
H. T. Pritchard Plant						
Unit 1	39,000	Oil	1949	2009	2009	60
Unit 2	39,000	Oil	1950	2010	2010	60
Unit 3	43,000	Coal	1951	2011	2011	60
Unit 4	56,000	Coal	1953	2013	2013	60
Unit 5	62,000	Coal	1953	2013	2013	60
Unit 6	99,000	Coal	1956	2016	2016	60
Petersburg Plant						
Unit 1	239,000	Coal	1967	2027	2027	60
Unit 2	418,000	Coal	1969	2029	2029	60
Unit 3	510,000	Coal	1977	2037	2017	40
Unit 4	515,000	Coal	1986	2046	2026	40
OTHER PRODUCTION PLANT						
Diesel Units						
E. W. Stout Plant						
Unit 1	3,000	Oil	1967	2002	2002	35
H. T. Pritchard Plant						
Unit 1	3,000	Oil	1967	2002	2002	35
Petersburg Plant						
Unit 1	3,000	Oil	1967	2002	2002	35
Unit 2	3,000	Oil	1967	2002	2002	35
Unit 3	3,000	Oil	1967	2002	2002	35
Combustion Turbine Units						
E. W. Stout Plant						
Unit 1	20,000	Oil	1973	2008	2008	35
Unit 2	20,000	Oil	1973	2008	2008	35
Unit 3	20,000	Oil	1973	2008	2008	35
Unit 4	80,000	Oil	1994	2029	2029	35
Unit 5	80,000	Oil	1995	2030	2030	35

Notes:

(a) Units retired in 1987.

INDIANAPOLIS POWER & LIGHT COMPANY
Comparison of Mortality Characteristics

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Existing Rates				Recommended Rates					
			Net Salvage				Interim Retirements			
Functional Group and Account	Average Service Life	Iowa Curve Type	Interim	Terminal	Interim Retirement Ratio	Interim Addition Ratio	Salvage	Cost of Removal	Net Salvage	Terminal Net Salvage
	years		%	%			%	%	%	$
STEAM PRODUCTION PLANT										
E. W. Stout Plant										
310.2 Land Rights (a)					0.0000	0.0	0	0	0	0
311 Structures and Improvements	50	SQ	(10)	(10)	0.0010	10.0	0	60	(60)	13,757,207
312.1 Boiler Plant Equipment	45	SQ	(10)	(10)	0.0030	5.0	0	30	(30)	42,967,202
312.2 Coal & Ash Handling Equipment	45	SQ	(10)	(10)	0.0050	4.5	5	20	(15)	8,192,911
314 Turbogenerator Units	45	SQ	(10)	(10)	0.0015	4.0	5	35	(30)	17,900,508
315 Accessory Electric Equipment	40	R4	(10)	(10)	0.0010	12.0	0	20	(20)	5,953,017
316 Miscellaneous Power Plant Equipment	40	SQ	(10)	(10)	0.0030	6.0	10	20	(10)	1,667,155
H. T. Pritchard Plant										
311 Structures and Improvements	50	SQ	(15)	(15)	0.0010	10.0	0	60	(60)	9,054,463
312.1 Boiler Plant Equipment	45	SQ	(15)	(15)	0.0030	5.0	0	30	(30)	27,954,050
312.2 Coal & Ash Handling Equipment	45	SQ	(15)	(15)	0.0050	4.5	5	20	(15)	5,340,510
314 Turbogenerator Units	45	SQ	(15)	(15)	0.0015	4.0	5	35	(30)	13,794,414
315 Accessory Electric Equipment	40	R4	(15)	(15)	0.0010	12.0	0	20	(20)	3,879,945
316 Miscellaneous Power Plant Equipment	40	SQ	(15)	(15)	0.0030	6.0	10	20	(10)	697,617
Petersburg Plant										
311 Structures and Improvements	45	SQ	(10)	(10)	0.0010	10.0	0	60	(60)	32,066,923
312.1 Boiler Plant Equipment	35	SQ	(10)	(10)	0.0030	5.0	0	30	(30)	134,277,694
312.2 Coal & Ash Handling Equipment	35	SQ	(10)	(10)	0.0050	4.5	5	20	(15)	20,443,722
314 Turbogenerator Units	35	SQ	(10)	(10)	0.0015	4.0	5	35	(30)	32,490,145
315 Accessory Electric Equipment	35	R4	(10)	(10)	0.0010	12.0	0	20	(20)	20,620,578
316 Miscellaneous Power Plant Equipment	35	SQ	(10)	(10)	0.0030	6.0	10	20	(10)	3,238,938
OTHER PRODUCTION PLANT										
344 Generators										
Stout Station	25	SQ	(10)	(10)	0.0015	7.0	0	5	(5)	77,000
Pritchard Station	25	SQ	(15)	(15)	0.0015	7.0	0	5	(5)	5,000
Petersburg Station	25	SQ	(10)	(10)	0.0015	7.0	0	5	(5)	14,000

Notes:
(a) Not previously depreciated.

SCHEDULE #3

INDIANAPOLIS POWER & LIGHT COMPANY **SCHEDULE 4**
Comparison of Mortality Characteristics

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Existing Rates			Recommended Rates				
Functional Group and Account	Average Service Life	Iowa Curve Type	Net Salvage	Average Service Life	Iowa Curve Type	Salvage	Cost of Removal	Net Salvage
	years		%	years		%	%	%
TRANSMISSION PLANT								
350.2 Land Rights	84	SQ	0	60	R5	0	0	0
352 Structures & Improvements	45	R4	(15)	45	R4	5	25	(20)
353 Station Equipment	31	S2	15	37	S-0.5	10	20	(10)
354 Towers & Fixtures	45	S2	(20)	50	R4	25	120	(95)
355 Poles & Fixtures	30	R3	20	33	S4	50	110	(60)
356 Overhead Conductors & Devices	29	S4	5	40	R4	70	130	(60)
357 Underground Conduit	40	R3	(5)	40	R3	0	15	(15)
358 Underground Conductors & Devices	35	R3	(5)	35	S0	0	45	(45)
ELECTRIC DISTRIBUTION PLANT								
360.2 Land Rights	46	SQ	0	40	R5	0	0	0
361 Structures & Improvements	35	R3	(25)	45	R3	5	25	(20)
362 Station Equipment	33	R2	10	40	S-0.5	15	25	(10)
364 Poles, Towers & Fixtures	25	R4	(65)	30	S5	60	195	(135)
365 Overhead Conductors & Devices	25	R4	(65)	30	S5	60	180	(120)
366 Underground Conduit	47	R2.5	(5)	50	R4	20	105	(85)
367 Underground Conductors & Devices	25	S4	0	25	S5	45	50	(5)
368 Line Transformers	32	R2.5	(50)	40	R1.5	10	15	(5)
369.1 Overhead Services	33	R2.5	(60)	37	S3	65	155	(90)
369.2 Underground Services	33	R2.5	(60)	26	S6	20	85	(65)
370 Meters	34	R2	5	30	R1.5	0	0	0
371 Installations on Customers' Premises	9	L3	(50)	18	S6	40	85	(45)
373 Street Lighting & Signal Systems	24	R0.5	(45)	26	L3	20	50	(30)
GENERAL PLANT								
390 Structures & Improvements	40	S-0.5	(20)	45	S-0.5	5	25	(20)
391.1 Office Furniture & Fixtures	21	S-0.5	5	25	L0	5	0	5
391.2 Computer Equipment	8	SQ	0	8	S1	5	0	5
392 Transportation Equipment	10	SC	30	9	S1	25	0	25
393 Stores Equipment	27	R5	10	30	L1.5	10	0	10
394 Tools, Shop & Garage Equipment	25	R3	5	28	L0.5	10	0	10
395 Laboratory Equipment	23	S6	0	28	L1.5	0	0	0
396 Power Operated Equipment	16	SC	25	15	L0.5	20	0	20
397 Communication Equipment	18	S6	0	12	L2	5	5	0
398 Miscellaneous Equipment	27	R2.5	0	33	S1	0	0	0

INDIANAPOLIS POWER & LIGHT COMPANY
Adjustment to Cost of Removal Factors to Recognize Misleading History

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Average Age of Property Retired		Cost of Removal					
Function and Account	Actual 1989-93	1993 Survivors at Retirement	Actual 1989-93	Selection Based on History	At Age of 1993 Survivors at Retirement	Difference (6) - (5)	Adjustment	Study Selection
	years	years	%	%	%	%	%	%
TRANSMISSION PLANT								
353 Station Equipment	17.3	42.9	15	15	35	20	5	20
354 Towers & Fixtures	22.4	50.4	101	100	425	325	20	120
355 Poles & Fixtures	29.6	32.7	112	110	115	5	0	110
356 Overhead Conductors & Devices	27.4	40.7	127	120	190	70	10	130
357 Underground Conduit	29.2	42.7	10	15	20	5	0	15
358 Underground Conductors & Devices	22.0	40.7	49	40	70	30	5	45
DISTRIBUTION PLANT								
362 Station Equipment	19.0	45.5	21	20	45	25	5	25
364 Poles, Towers & Fixtures	31.6	30.3	205	200	190	(10)	(5)	195
365 Overhead Conductors & Devices	30.8	30.2	179	180	175	(5)	0	180
366 Underground Conduit	26.3	50.5	82	90	235	145	15	105
367 Underground Conductors & Devices	20.1	25.2	47	50	55	5	0	50
369.1 Overhead Services	32.9	39.0	146	150	170	20	5	155
369.2 Underground Services	23.4	26.0	86	80	105	25	5	85

Schedule 5

INDIANAPOLIS POWER & LIGHT COMPANY
Annual Additions & Retirements @ December 31, 1993
Account 312.1, Boiler Plant Equipment
E. W. Stout Station

Interim Retirement Rate: 0.3000%
Interim Additions Rate: 5.0

(1)	(2a)	(2b)	(2c)	(3a)	(3b)	(3c)	(4a)	(4b)	(4c)	(5a)	(5b)	(5c)
	Unit 3 - Retire 2001			Unit 4 - Retire 2007			Unit 7 - Retire 2013			Unit 5 - Retire 2018		
Year	Retmts.	Additions	Balance	Retmts.	Additions	Balance	Retmts.	Additions	Balance	Retmts.	Additions	Balance
	$	$	$	$	$	$	$	$	$	$	$	$
1993			974,782			952,490			46,724,009			15,436,845
1994	2,924	161,102	1,132,960	2,857	161,102	1,110,735	140,172	3,378,261	49,962,098	46,311	2,022,087	17,412,621
1995	3,399	0	1,129,561	3,332	0	1,107,402	149,886	1,081,164	50,893,376	52,238	827,130	18,187,514
1996	3,389	16,943	1,143,116	3,322	16,611	1,120,691	152,680	0	50,740,696	54,563	272,813	18,405,764
1997	3,429	17,147	1,156,833	3,362	16,810	1,134,139	152,222	0	50,588,474	55,217	276,086	18,626,633
1998			1,156,833	3,402	17,012	1,147,749	151,765	0	50,436,708	55,880	279,399	18,850,153
1999			1,156,833	3,443	17,216	1,161,522	151,310	0	50,285,398	56,550	282,752	19,076,355
2000			1,156,833	3,485	17,423	1,175,460	150,856	0	50,134,542	57,229	286,145	19,305,271
2001	1,156,833		0	3,526	17,632	1,189,566	150,404	0	49,984,138	57,916	289,579	19,536,934
2002				3,569	17,843	1,203,841	149,952	0	49,834,186	58,611	293,054	19,771,377
2003				3,612	18,058	1,218,287	149,503	0	49,684,683	59,314	296,571	20,008,634
2004						1,218,287	149,054	0	49,535,629	60,026	300,130	20,248,738
2005						1,218,287	148,607	0	49,387,023	60,746	303,731	20,491,722
2006						1,218,287	148,161	0	49,238,861	61,475	307,376	20,737,623
2007				1,218,287		0	147,717	0	49,091,145	62,213	311,064	20,986,475
2008							147,273	0	48,943,871	62,959	314,797	21,238,312
2009							146,832	0	48,797,040	63,715	318,575	21,493,172
2010									48,797,040	64,480	322,398	21,751,090
2011									48,797,040	65,253	326,266	22,012,103
2012									48,797,040	66,036	330,182	22,276,248
2013							48,797,040		0	66,829	334,144	22,543,563
2014										67,631	338,153	22,814,086
2015												22,814,086
2016												22,814,086
2017												22,814,086
2018										22,814,086		0
2019												
2020												
2021												

INDIANAPOLIS POWER & LIGHT COMPANY
Annual Additions & Retirements @ December 31, 1993
Account 312.1, Boiler Plant Equipment
E. W. Stout Station

Interim Retirement Rate: 0.3000%
Interim Additions Rate: 5.0

(1)	(6a)	(6b)	(6c)	(7a)	(7b)	(7c)	(8a)	(8b)
	Unit 6 & Common - Retire 2021			Totals - All Years			Retirements	
Year	Retmts.	Additions	Balance	Retmts.	Additions	Balance	Interim	Terminal
	$	$	$	$	$	$	$	$
1993			26,971,797			91,059,923		
1994	80,915	5,155,550	32,046,432	273,180	10,878,102	101,664,845	273,180	
1995	96,139	1,891,130	33,841,423	304,995	3,799,425	105,159,276	304,995	
1996	101,524	507,621	34,247,520	315,478	813,988	105,657,786	315,478	
1997	102,743	513,713	34,658,490	316,973	823,756	106,164,569	316,973	
1998	103,975	519,877	35,074,392	315,023	816,289	106,665,835	315,023	
1999	105,223	526,116	35,495,285	316,527	826,084	107,175,392	316,527	
2000	106,486	532,429	35,921,228	318,056	835,997	107,693,334	318,056	
2001	107,764	538,818	36,352,283	1,476,442	846,029	107,062,921	319,610	1,156,833
2002	109,057	545,284	36,788,510	321,189	856,182	107,597,914	321,189	
2003	110,366	551,828	37,229,972	322,794	866,456	108,141,576	322,794	
2004	111,690	558,450	37,676,732	320,770	858,579	108,679,386	320,770	
2005	113,030	565,151	38,128,853	322,383	868,882	109,225,884	322,383	
2006	114,387	571,933	38,586,399	324,023	879,309	109,781,170	324,023	
2007	115,759	578,796	39,049,436	1,543,975	889,860	109,127,055	325,689	1,218,287
2008	117,148	585,742	39,518,029	327,381	900,539	109,700,213	327,381	
2009	118,554	592,770	39,992,245	329,101	911,345	110,282,457	329,101	
2010	119,977	599,884	40,472,152	184,456	922,281	111,020,282	184,456	
2011	121,416	607,082	40,957,818	186,670	933,349	111,766,961	186,670	
2012	122,873	614,367	41,449,312	188,910	944,549	112,522,600	188,910	
2013	124,348	621,740	41,946,704	48,988,216	955,883	64,490,267	191,177	48,797,040
2014	125,840	629,201	42,450,064	193,471	967,354	65,264,150	193,471	
2015	127,350	636,751	42,959,465	127,350	636,751	65,773,551	127,350	
2016	128,878	644,392	43,474,978	128,878	644,392	66,289,064	128,878	
2017	130,425	652,125	43,996,678	130,425	652,125	66,810,764	130,425	
2018			43,996,678	22,814,086	0	43,996,678	0	22,814,086
2019			43,996,678	0	0	43,996,678	0	
2020			43,996,678	0	0	43,996,678	0	
2021	43,996,678		0	43,996,678	0	(0)	0	43,996,678

INDIANAPOLIS POWER & LIGHT COMPANY
Depreciation Rate Calculation
Account 312.1, Steam - Boiler Plant Equipment
E. W. Stout Station

Interim Net Salvage:	-30.0%
Terminal Net Salvage:	-36.4%
Average Net Salvage:	-36.1%
Book Reserve Ratio:	22.5%
Average Remaining Life:	20.591 yrs
Interim Additions Factor:	5.0
Interim Retirement Rate:	0.3000%
Depreciation Rate:	5.51%

(1) Year	(1) Year	(9) Interim Retirements $	(10) Interim Net Salvage $	(11) Terminal Retirements $	(12) Terminal Net Salvage $	(13) Interim Additions $	(14) Plant Balance $	(15) Average Balance $	(16) Annual Accrual $	(17) Book Reserve $
1993	1993						91,059,923			28,031,862
1994	1994	273,180	(81,954)	0	0	10,878,102	101,664,845	96,362,384	5,314,080	32,990,809
1995	1995	304,995	(91,498)	0	0	3,799,425	105,159,276	103,412,060	5,702,848	38,297,163
1996	1996	315,478	(94,643)	0	0	813,988	105,657,786	105,408,531	5,812,947	43,699,989
1997	1997	316,973	(95,092)	0	0	823,756	106,164,569	105,911,178	5,840,666	49,128,589
1998	1998	315,023	(94,507)	0	0	816,289	106,665,835	106,415,202	5,868,461	54,587,521
1999	1999	316,527	(94,958)	0	0	826,084	107,175,392	106,920,614	5,896,333	60,072,369
2000	2000	318,056	(95,417)	0	0	835,997	107,693,334	107,434,363	5,924,665	65,583,561
2001	2001	319,610	(95,883)	1,156,833	0	846,029	107,062,921	107,378,128	5,921,564	69,932,800
2002	2002	321,189	(96,357)	0	0	856,182	107,597,914	107,330,418	5,918,933	75,434,187
2003	2003	322,794	(96,838)	0	0	866,456	108,141,576	107,869,745	5,948,675	80,963,230
2004	2004	320,770	(96,231)	0	0	858,579	108,679,386	108,410,481	5,978,495	86,524,724
2005	2005	322,383	(96,715)	0	0	868,882	109,225,884	108,952,635	6,008,393	92,114,018
2006	2006	324,023	(97,207)	0	0	879,309	109,781,170	109,503,527	6,038,773	97,731,561
2007	2007	325,689	(97,707)	1,218,287	0	889,860	109,127,055	109,454,113	6,036,048	102,125,927
2008	2008	327,381	(98,214)	0	0	900,539	109,700,213	109,413,634	6,033,815	107,734,146
2009	2009	329,101	(98,730)	0	0	911,345	110,282,457	109,991,335	6,065,674	113,371,989
2010	2010	184,456	(55,337)	0	0	922,281	111,020,282	110,651,370	6,102,073	119,234,269
2011	2011	186,670	(56,001)	0	0	933,349	111,766,961	111,393,622	6,143,005	125,134,604
2012	2012	188,910	(56,673)	0	0	944,549	112,522,600	112,144,780	6,184,429	131,073,450
2013	2013	191,177	(57,353)	48,797,040	0	955,883	64,490,267	88,506,433	4,880,849	86,908,730
2014	2014	193,471	(58,041)	0	0	967,354	65,264,150	64,877,209	3,577,773	90,234,991
2015	2015	127,350	(38,205)	0	0	636,751	65,773,551	65,518,851	3,613,157	93,682,593
2016	2016	128,878	(38,664)	0	0	644,392	66,289,064	66,031,308	3,641,417	97,156,468
2017	2017	130,425	(39,127)	0	0	652,125	66,810,764	66,549,914	3,670,017	100,656,933
2018	2018	0	0	22,814,086	0	0	43,996,678	55,403,721	3,055,340	80,898,186
2019	2019	0	0	0	0	0	43,996,678	43,996,678	2,426,277	83,324,464
2020	2020	0	0	0	0	0	43,996,678	43,996,678	2,426,277	85,750,741
2021	2021	0	0	43,996,678	(42,967,202)	0	(0)	21,998,339	1,213,139	(0)

Petitioner's Exhibit DSR-3
I.U.R.C. Cause No. 39938

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS, PUBLIC UTILITY DEPRECIATION PRACTICES (page 223)
Published December 1968

G. ESTIMATING FUTURE SERVICE LIVES

1. Historical Data.

Historical data are an important factor in estimating service lives and should be accumulated to the extent practicable by each utility.

2. Future Conditions.

Depreciation rates apply primarily to the life of depreciable plant in the future. The depreciation engineer must consider probable future conditions as well as past service life indications in determining depreciation rates.

3. Depreciation as a Reflection of Actual Conditions.

Utilities must be encouraged to make sound and reasonable depreciation studies. Experience both as to past service life indications and mortality dispersion is a fundamental and important guide in estimating future depreciation. The other factors affecting depreciation as set out in Chapter VII are most important, however, blind adherence to past service life indications may yield poor results when translated verbatim into depreciation rates. Therefore, the depreciation engineer must become familiar with the operations and changes in the art of the industry as well as the current practices, policy and future plans of the particular utility under study.

Petitioner's Exhibit DSR-4
I.U.R.C. Cause No. 39938

AMERICAN GAS ASSOCIATION AND EDISON ELECTRIC INSTITUTE, AN INTRODUCTION TO DEPRECIATION OF PUBLIC UTILITY PLANT AND PLANT OF OTHER INDUSTRIES (page 25)
March 18, 1975

Methods of Estimation: There are various accepted methods for computing average service life, all of them using past experience in varying degrees, and any one of them furnishing a base on which the analyst's judgment may be formed. It must be emphasized that the objective is to select an average service life applicable to <u>surviving</u> plant. It may be a nice exercise in arithmetic to show that the average service life of the plant retired during the past 25 years from some particular plant account had an average service life of 36.68 years, but such information is worthless. What must be estimated is the average life and average remaining life of the plant in service at the time of the study. Past experience can be of considerable help in doing this, since experience has taught that the past is a guide to the future, but it must be recognized that <u>the future never does exactly duplicate the past</u>. Also, the accuracy and the extent of the past experience available must be carefully considered.

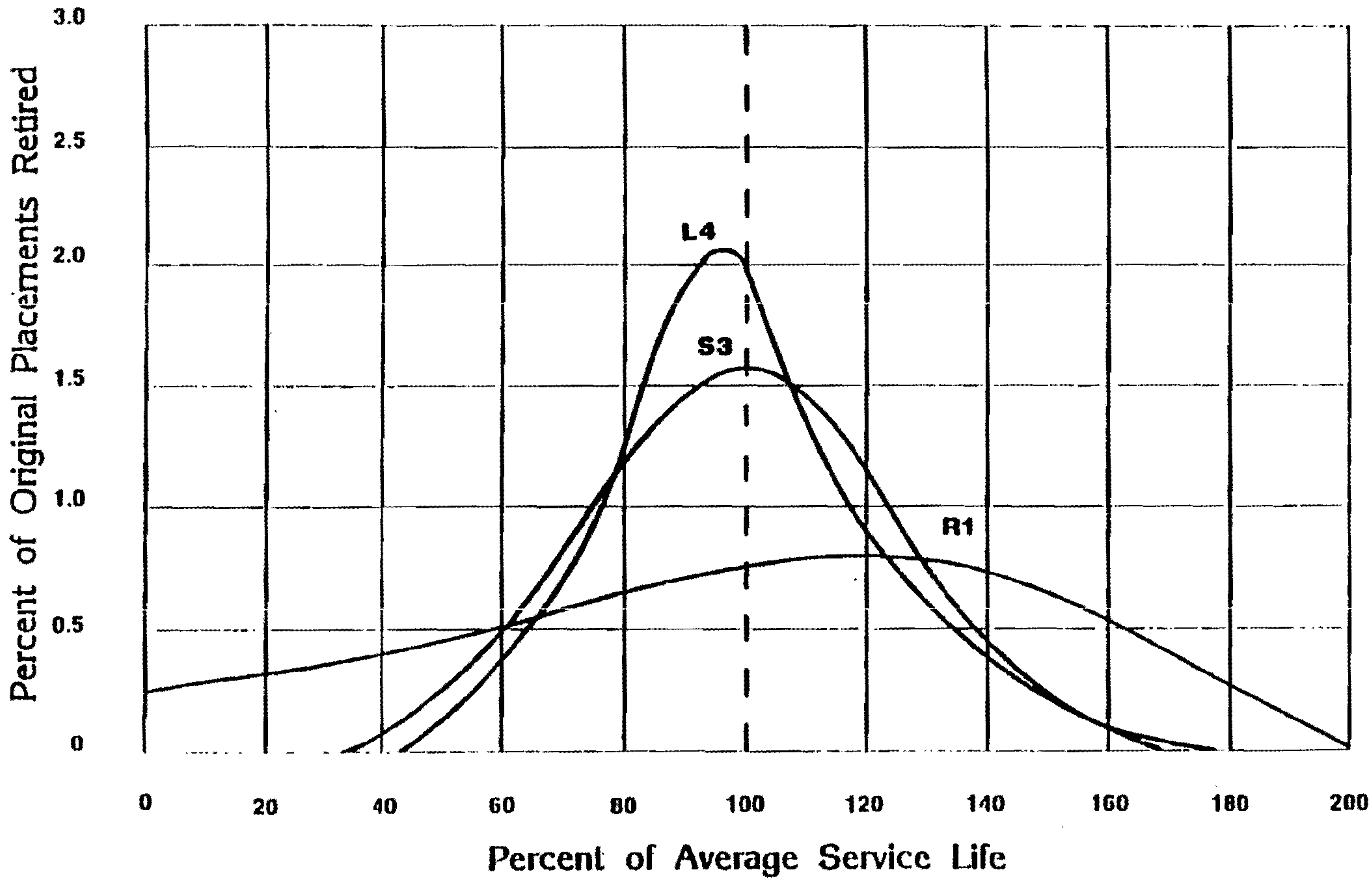
Each time the analyst faces the problem of estimating average service life he must be aware of and weigh the factors which bring about retirement of units of property and thus affect the service life. As pointed out in the definitions of depreciation, such factors comprise wear and tear, deterioration, inadequacy, obsolescence, and so on. For example, experience has shown that for many types of plant the physical wearing out of the property might be far less of a factor in causing retirements than obsolescence, inadequacy, requirements of public authorities, and so on. (Emphasis in original)

PUBLIC UTILITY DEPRECIATION PRACTICES (page 24)

Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage, as the name implies, is the difference between the gross salvage that will be obtained when the asset is disposed of and the cost of removing it. Positive net salvage occurs when gross salvage exceeds cost of removal, and negative net salvage occurs when cost of removal exceeds gross salvage. Thus the intent of the present concept is to allocate the net cost of an asset to annual accounting periods, making due allowance of the net salvage, positive or negative, that will be obtained when the asset is retired. This concept carries with it the thought that ownership of property entails the responsibility for its ultimate abandonment or removal. Hence if current users of the property benefit from its use, they should pay their pro rata share of the costs involved in the abandonment or removal of the property.

This treatment of salvage is in harmony with generally accepted accounting practices and tends to remove from the income statement fluctuations caused by erratic, although necessary, abandonment and uneconomical removal operations. It also has the advantage that current consumers pay a fair share, even though estimated, of the costs associated with the property devoted to their service.

Retirement Dispersion Defined
By Iowa Type Curves



DONALD S. ROFF

Petitioner's Exhibit DSR-6
I.U.R.C. Cause No. 39938

INDIANAPOLIS POWER & LIGHT COMPANY
Sensitivity of Cost of Removal to Age of Retirements
Account 364, Poles, Towers & Fixtures

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line	Transaction Year	Age @ 12-31-1993	Amount Retired	Weighted (2) x (3)	Average Dollar Age	Weighted (3) x (5)	Handy-Whitman Index
		years	$	$-years	years	$-years	
	CURRENT RETIREMENTS						
1	1989	4.5	294,837	1,326,767	30.43	8,971,890	
2	1990	3.5	333,396	1,166,886	31.18	10,395,287	
3	1991	2.5	258,191	645,478	31.69	8,182,073	
4	1992	1.5	141,497	212,246	32.69	4,625,537	
5	1993	0.5	302,286	151,143	32.67	9,875,684	
6	1989-93	2.63	1,330,207	3,502,519	31.61	42,050,471	
7	Average Retirement Year			1990.9			
8	Average Vintage Year			1959.3		Index:	49
9	Experienced Salvage			76 %			
10	Experienced Cost of Removal			205 %			
	TERMINAL RETIREMENTS						
11	Average Service Life			30.0 years			
12	Average Remaining Life			17.4 years			
13	Average Age of Survivors			12.9 years			
	Age at Retirement:						
14	Whole Life Basis			30.0 years			
15	Remaining Life Basis			30.3 years			
	Vintage at Retirement:						
16	Whole Life Basis			1960.9		Index:	52
17	Remaining Life Basis			1960.6		Index:	52
	Cost of Removal:						
18	Whole Life Basis			193 %			
19	Remaining Life Basis			193 %			

DONALD S. ROFF

INDIANAPOLIS POWER & LIGHT COMPANY
Comparison of IPL Rates With Other Indiana Electric Utilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	12-31-1993	IPL Rates		IMPCO Rates		NIPSCO Rates		PSI Rates		SIGECO Rates	
Functional Group and Account	Depreciable Balance	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
	$	%	$	%	$	%	$	%	$	%	$
STEAM PRODUCTION PLANT											
E. W. Stout Plant											
310.2 Land Rights	194	3.64	7	3.64	7	3.64	7	3.64	7	3.64	7
311 Structures & Improvements	29,155,499	4.50	1,311,997	4.47	1,303,251	3.09	900,905	4.26	1,242,024	3.00	874,665
312.1 Boiler Plant Equipment	91,059,922	5.51	5,017,402	4.72	4,298,028	3.98	3,624,185	4.60	4,188,756	4.00	3,642,397
312.2 Coal & Ash Handling Equipment	17,363,147	5.20	902,884	4.72	819,541	3.98	691,053	4.60	798,705	4.00	694,526
314 Turbogenerator Units	37,936,351	4.70	1,783,008	5.66	2,147,197	3.45	1,308,804	4.49	1,703,342	4.00	1,517,454
315 Accessory Electric Equipment	12,616,165	3.99	503,385	4.05	510,955	3.78	476,891	4.36	550,065	4.00	504,647
316 Miscellaneous Power Plant Equipment	3,533,183	4.73	167,120	5.17	182,866	4.13	145,920	4.96	175,248	4.00	141,327
Total E. W. Stout Plant	191,664,481	5.05	9,685,803	4.83	9,261,645	3.73	7,147,765	4.52	8,658,145	3.85	7,375,023
H. T. Pritchard Plant											
311 Structures & Improvements	15,358,485	5.45	837,037	4.47	686,524	3.09	474,577	4.26	654,271	3.00	460,755
312.1 Boiler Plant Equipment	47,416,599	6.96	3,300,195	4.72	2,238,063	3.98	1,887,181	4.60	2,181,164	4.00	1,896,664
312.2 Coal & Ash Handling Equipment	9,058,752	6.16	558,019	4.72	427,573	3.98	360,538	4.60	416,703	4.00	362,350
314 Turbogenerator Units	23,398,549	5.21	1,219,064	5.66	1,324,358	3.45	807,250	4.49	1,050,595	4.00	935,942
315 Accessory Electric Equipment	6,581,293	5.19	341,569	4.05	266,542	3.78	248,773	4.36	286,944	4.00	263,252
316 Miscellaneous Power Plant Equipment	1,183,322	6.24	73,839	5.17	61,178	4.13	48,871	4.96	58,693	4.00	47,333
Total H. T. Pritchard Plant	102,997,000	6.15	6,329,723	4.86	5,004,238	3.72	3,827,190	4.51	4,648,370	3.65	3,966,296
Petersburg Plant											
311 Structures & Improvements	133,726,316	3.04	4,065,280	4.47	5,977,566	3.09	4,132,143	4.28	5,696,741	3.00	4,011,789
312.1 Boiler Plant Equipment	559,968,338	3.20	17,918,987	4.72	26,430,506	3.98	22,286,740	4.60	25,758,544	4.00	22,398,734
312.2 Coal & Ash Handling Equipment	85,264,942	3.15	2,685,531	4.72	4,024,033	3.98	3,393,147	4.60	3,921,727	4.00	3,410,198
314 Turbogenerator Units	135,491,249	2.84	3,847,951	5.66	7,668,805	3.45	4,674,448	4.49	8,083,557	4.00	5,419,650
315 Accessory Electric Equipment	85,992,470	2.64	2,270,201	4.05	3,482,695	3.78	3,250,515	4.36	3,749,272	4.00	3,439,699
316 Miscellaneous Power Plant Equipment	13,507,105	2.73	368,744	5.17	698,317	4.13	557,843	4.96	669,952	4.00	540,284
Total Petersburg Plant	1,013,940,420	3.07	31,156,694	4.76	48,281,922	3.78	38,294,836	4.52	45,879,793	3.87	39,220,354
Total Steam Production Plant	1,308,601,881	3.60	47,172,220	4.78	62,547,805	3.77	49,269,791	4.52	59,186,308	3.86	50,561,673
COMMON STEAM PRODUCTION PLANT											
Total	55,809,069										
Steam Heat Operations @ 76.9%	(42,917,174)										
Electric Operations	12,891,895	2.72	350,660	2.72	350,660	2.72	350,660	2.72	350,660	2.72	350,660
OTHER PRODUCTION PLANT											
344 Generators											
E. W. Stout Plant	7,005,488	3.34	233,983	3.64	255,000	3.78	264,807	2.04	142,912	5.00	350,274
H. T. Pritchard Plant	213,347	3.39	7,232	3.64	7,766	3.78	8,065	2.04	4,352	5.00	10,667
Petersburg Plant	684,269	4.82	32,982	3.64	24,907	3.78	25,865	2.04	13,959	5.00	34,213
Total Other Production Plant	7,903,104	3.47	274,197	3.64	287,673	3.78	298,737	2.04	161,223	5.00	395,154

INDIANAPOLIS POWER & LIGHT COMPANY

Comparison of IPL Rates With Other Indiana Electric Utilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	12-31-1993	IPL Rates		IMPCO Rates		NIPSCO Rates		PSI Rates		SIGECO Rates	
Functional Group and Account	Depreciable Balance	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
	$	%	$	%	$	%	$	%	$	%	$
TRANSMISSION PLANT											
350.2 Land Rights	16,705,216	1.84	307,376	1.38	230,532	2.58	430,995	1.33	222,179	2.50	417,630
352 Structures & Improvements	3,280,855	2.39	78,412	1.57	51,509	2.74	89,895	1.83	60,040	2.85	93,504
353 Station Equipment	94,852,100	2.63	2,494,610	2.00	1,897,042	2.54	2,409,243	2.12	2,010,865	3.60	3,414,676
354 Towers & Fixtures	38,730,666	4.42	1,711,895	1.81	701,025	2.81	1,088,332	2.13	824,963	3.33	1,289,731
355 Poles & Fixtures	18,841,350	6.52	1,228,456	2.33	439,003	3.82	719,740	3.61	680,173	5.00	942,068
356 Overhead Conductors & Devices	41,709,358	4.30	1,793,502	1.61	671,521	3.05	1,272,135	2.15	898,751	3.60	1,501,537
357 Underground Conduit	1,309,108	2.76	36,131	1.87	24,480	2.44	31,942	2.76	36,131	2.00	26,182
358 Underground Conductors & Devices	1,511,943	4.28	64,711	1.63	24,645	2.25	34,019	4.28	64,711	2.83	42,788
Total Transmission Plant	216,940,596	3.56	7,715,093	1.86	4,039,757	2.80	6,076,301	2.21	4,795,813	3.56	7,728,116
ELECTRIC DISTRIBUTION PLANT											
360.2 Land Rights	187,470	2.91	5,455	1.61	3,018	2.81	5,268	1.39	2,606	2.91	5,455
361 Structures & Improvements	5,106,974	2.42	123,589	2.06	105,204	2.24	114,396	2.63	134,313	2.86	146,059
362 Station Equipment	89,866,244	2.55	2,291,589	3.31	2,974,573	2.49	2,237,669	2.91	2,615,108	4.00	3,594,650
364 Poles, Towers & Fixtures	52,168,893	8.89	4,637,815	5.20	2,712,782	3.83	1,998,069	3.65	1,904,165	4.00	2,086,756
365 Overhead Conductors & Devices	61,353,152	8.11	4,975,741	4.62	2,834,516	4.72	2,895,869	2.51	1,539,964	3.33	2,043,060
366 Underground Conduit	33,086,052	4.30	1,422,700	1.91	631,944	1.86	615,401	1.51	499,599	2.00	661,721
367 Underground Conductors & Devices	73,009,862	4.23	3,088,317	2.97	2,168,393	3.51	2,562,646	2.70	1,971,266	2.29	1,671,926
368 Line Transformers	101,413,001	1.83	1,855,858	4.17	4,228,922	3.62	3,671,151	3.76	3,813,129	3.60	3,650,868
369.1 Overhead Services	19,547,304	5.88	1,149,381	4.70	918,723	6.23	1,217,797	5.07	991,048	3.39	662,654
369.2 Underground Services	25,053,873	6.93	1,736,233	4.70	1,177,532	6.23	1,560,856	5.07	1,270,231	3.39	849,326
370 Meters	38,716,442	3.72	1,440,262	3.44	1,331,846	3.39	1,312,487	3.66	1,417,022	2.86	1,107,290
371 Installations on Customers' Premises	16,531,744	8.84	1,461,406	8.60	1,421,730	9.64	1,593,660	7.11	1,175,407	4.00	661,270
373 Street Lighting & Signal Systems	32,940,900	4.57	1,505,399	6.38	2,101,629	5.64	1,857,867	5.51	1,815,044	3.33	1,096,932
Total Distribution Plant	548,981,911	4.68	25,693,735	4.12	22,610,812	3.94	21,643,136	3.49	19,148,902	3.32	18,237,967
GENERAL PLANT											
390 Structures & Improvements	41,226,138	2.69	1,108,983	3.23	1,331,604	3.03	1,249,152	2.70	1,113,106	2.00	824,523
391.1 Office Furniture & Fixtures	6,978,983	3.36	234,494	3.72	259,618	3.10	216,348	4.73	330,108	22.86	1,595,396
391.2 Computer Equipment	11,748,644	11.85	1,392,214	3.72	437,050	3.10	364,208	4.73	555,711	22.86	2,685,740
392 Transportation Equipment	15,294,901	11.77	1,800,210	11.77	1,800,210	11.77	1,800,210	11.77	1,800,210	10.85	1,659,497
393 Stores Equipment	1,033,840	2.66	27,500	5.47	56,551	2.40	24,812	4.67	48,280	9.20	95,113
394 Tools, Shop & Garage Equipment	8,786,755	2.92	256,573	6.58	578,168	3.49	306,658	3.25	285,570	6.00	527,205
395 Laboratory Equipment	4,674,502	3.40	158,933	4.93	230,453	3.06	143,040	2.48	115,928	4.00	186,980
396 Power Operated Equipment	2,194,637	6.84	150,113	4.81	105,562	6.84	150,113	6.84	150,113	9.00	197,517
397 Communication Equipment	4,375,021	10.70	468,127	4.30	188,126	3.74	163,626	5.49	240,189	10.00	437,502
398 Miscellaneous Equipment	1,278,111	2.75	35,148	2.60	33,231	5.05	64,545	3.54	45,245	5.00	63,906
Total General Plant	97,591,532	5.77	5,632,295	5.14	5,020,573	4.59	4,482,712	4.80	4,684,458	8.48	8,273,379
Steam Heat Operations @ 2.0%	(1,951,831)	5.77	(112,646)	5.14	(100,411)	4.59	(89,654)	4.80	(93,689)	8.48	(165,468)
Electric Operations	95,639,701	5.77	5,519,649	5.14	4,920,162	4.59	4,393,058	4.80	4,590,769	8.48	8,107,911
Total Electric Plant	2,190,959,088	3.96	86,725,554	4.32	94,756,869	3.74	82,031,683	4.03	88,233,675	3.90	85,381,481

INDIANAPOLIS POWER LIGHT COMPANY
HISTORICAL UNDERGROUND DISTRIBUTION LINE OPERATION AND MAINTENANCE COST PER UNDERGROUND DISTRIBUTION MILE

YEAR	FERC ACCOUNT NO. 584 OPERATION UNDERGROUND LINES ($000s)	FERC ACCOUNT NO. 594 MAINTENANCE UNDERGROUND LINES ($000s)	TOTAL ($000s)	UNDERGROUND DISTRIBUTION MILES	COST PER UG MILES 584	COST PER UG MILES 594	COST PER UG MILES TOTAL
1994	$1,322	$2,758	$4,080	4,900	$270	$563	$833
1995	$1,663	$2,254	$3,917	5,148	$323	$438	$761
1996	$1,507	$2,557	$4,064	5,276	$286	$485	$770
1997	$1,360	$2,410	$3,770	5,520	$246	$437	$683
1998	$1,223	$2,975	$4,198	5,990	$204	$497	$701
1999	$1,527	$2,455	$3,982	6,487	$235	$378	$614
2000	$1,340	$3,010	$4,350	6,588	$203	$457	$660
2001	$1,611	$2,742	$4,353	6,689	$241	$410	$651
2002	$1,499	$1,922	$3,421	6,789	$221	$283	$504
2003	$1,614	$1,747	$3,361	4,110	$393	$425	$818
2004	$1,253	$2,467	$3,720	4,259	$294	$579	$873
2005	$923	$3,392	$4,315	4,008	$230	$846	$1,077
2006	$806	$2,545	$3,351	4,469	$180	$569	$750
2007	$1,165	$2,632	$3,797	4,736	$246	$556	$802
2008	$1,244	$2,746	$3,990	4,518	$275	$608	$883
2009	$1,203	$2,845	$4,048	4,640	$259	$613	$872
2010	$1,228	$2,751	$3,979	4,587	$268	$600	$867
2011	$1,164	$3,803	$4,967	4,613	$252	$824	$1,077
2012	$1,262	$3,498	$4,760	4,756	$265	$735	$1,001
2013	$1,190	$2,892	$4,082	4,779	$249	$605	$854
2014	$1,091	$2,750	$3,841	4,811	$227	$572	$798

NOTES:

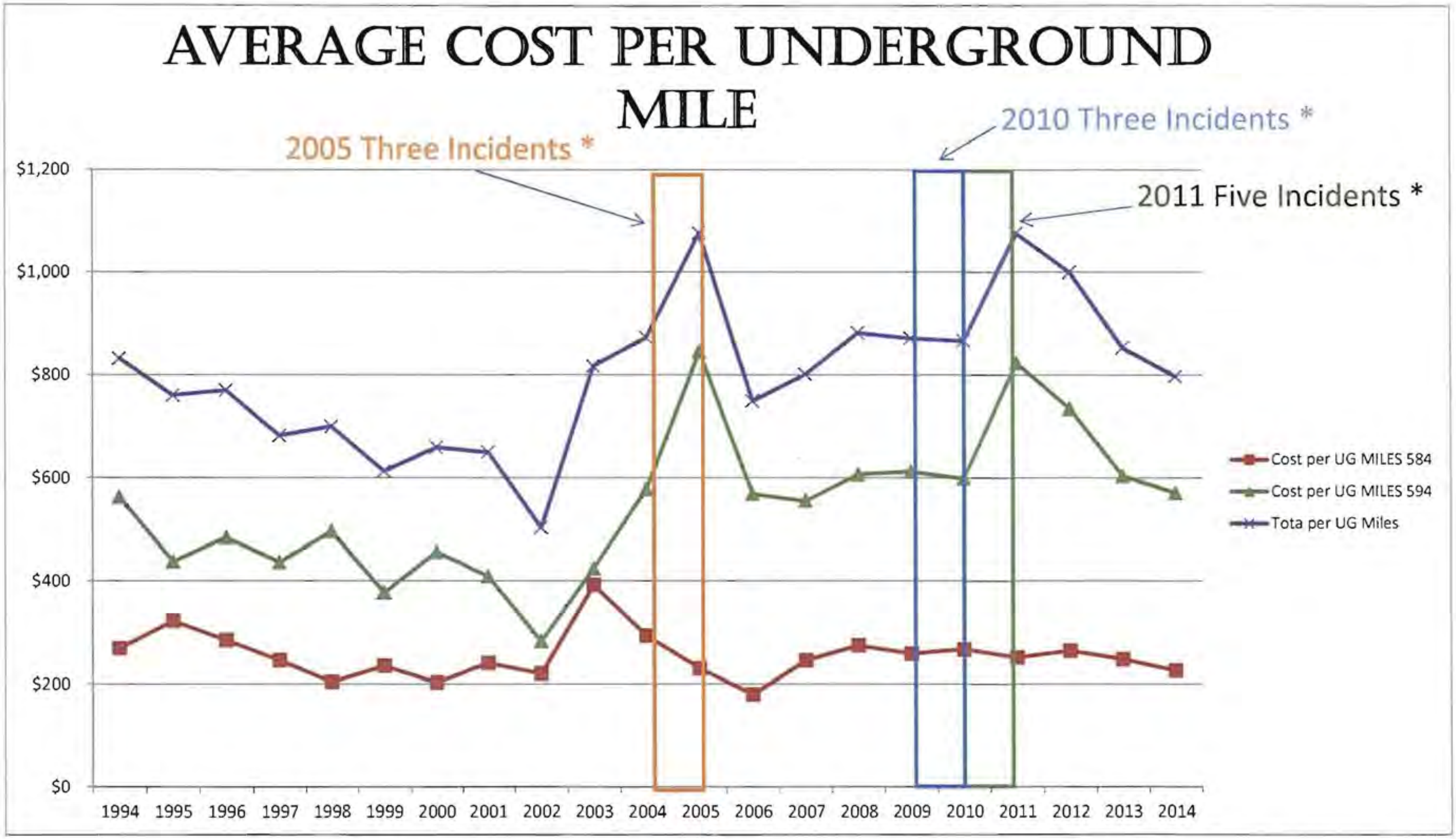
1 The underground distribution mileage numbers were derived from the filed SEC 10-K with the exception of 2000 and 2001
The 2000 and the 2001 underground distribution mileage figures were extrapolated based on the reported figures for 1999 and 2002.

2 Unable to find a reason for the reduction in reported underground distribution mileage 2002 and 2003.

3 Based on the Consumer Price Index average for each year compiled by the U.S. Bureau of Labor Statistics a $1.00 spent in 1994 would equate to $1.22 today

INDIANAPOLIS POWER LIGHT COMPANY

HISTORICAL UNDERGROUND DISTRIBUTION LINE OPERATION AND MAINTENANCE COST
PER
UNDERGROUND DISTRIBUTION MILE



* Source - Independent Assessment of Indianapolis Power & Light's Downtown Underground Network - O'Neill Management Consulting - December 2011, pg 10 & 11

INDIANAPOLIS POWER LIGHT COMPANY
OPERATING AND MAINTENANCE EXPENSE
UNDERGROUND LINES
2007 TO 2014

FERC ACCOUNT NUMBER	FERC ACCOUNT DESCRIPTION	YEAR 2007	YEAR 2008	YEAR 2009	YEAR 2010	YEAR 2011	YEAR 2012	YEAR 2013	YEAR 2014
584	UNDERGROUND LINE EXPENSE	$1,164,631	$1,244,158	$1,203,357	$1,227,717	$1,163,608	$1,262,269	$1,190,308	$1,091,000
594	MAINTENANCE OF UNDERGROUND LINES	2,631,586	2,746,148	2,844,861	2,751,126	3,802,544	3,497,888	2,891,925	2,750,000
	TOTAL UNDERGROUND LINE EXPENSE	$3,796,217	$3,990,306	$4,048,218	$3,978,843	$4,966,152	$4,760,157	$4,082,233	$3,841,000
(1)	REPORTED UNDERGROUND CIRCUIT MILES	4,736	4,518	4,640	4,587	4,613	4,756	4,779	4,811
	AVERAGE COST PER UNDERGROUND MILE	$802	$883	$872	$867	$1,077	$1,001	$854	$798
583	OVERHEAD LINE EXPENSE	$1,565,000	$2,286,000	$2,271,000	$2,184,000	$1,373,000	$1,298,000	$1,370,000	$1,561,000
593	MAINTENANCE OF OVERHEAD LINES	10,155,000	15,574,000	10,877,000	11,337,000	11,661,000	13,450,000	13,135,000	16,044,000
	TOTAL OVERHEAD LINE EXPENSE	$11,720,000	$17,860,000	$13,148,000	$13,521,000	$13,034,000	$14,748,000	$14,505,000	$17,605,000
(1)	REPORTED OVERHEAD CIRCUIT MILES	6,176	5,861	6,168	6,168	5,864	6,131	6,131	6,126
	AVERAGE COST PER OVERHEAD MILE	$1,898	$3,047	$2,132	$2,192	$2,223	$2,405	$2,366	$2,874
	O&M COSTS PER MILE NORTH CAROLINA STUDY NOVEMBER 2003: (2)								
	DUCT BANK URBAN UNDERGROUND:								
	HIGH COST	$6,404	$6,404	$6,404	$6,404	$6,404	$6,404	$6,404	$6,404
	LOW COST	$1,700	$1,700	$1,700	$1,700	$1,700	$1,700	$1,700	$1,700
	AVERAGE	$4,052	$4,052	$4,052	$4,052	$4,052	$4,052	$4,052	$4,052
	DIRECT BURIED UNDERGROUND:								
	HIGH COST	$1,160	$1,160	$1,160	$1,160	$1,160	$1,160	$1,160	$1,160
	LOW COST	$614	$614	$614	$614	$614	$614	$614	$614
	AVERAGE	$920	$920	$920	$920	$920	$920	$920	$920

NOTES:

(1) DERIVED FROM IPL FORM 10-K

(2) REPORT OF THE PUBLIC STAFF TO THE NORTH CAROLINA NATURAL DISASTER PREPAREDNESS TASK FORCE: "THE FEASIBILITY OF PLACING ELECTRIC DISTRIBUTION FACILITIES UNDERGROUND" NOVEMBER 2003