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PUC BULLETIN

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ELECTRIC

Editor's Note: The Examiner's Report and final Order in Docket Nos. 6765/6766, Petitions of Houston Lighting & Power for Authority to Change Rates and for Approval of Proposed Interim Accounting Treatment for Limestone Unit I, will be continued in the September, October, November, and December issues of the **PUC Bulletin**, Volume 13, Nos. 1-4.

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- Rate filing package, Class C & D (electric & telephone)
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- Class A & B quarterly electric report
- Class C & D annual electric report
- Annual peak demand and consumption report
- Quarterly peak demand and consumption report

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PETITION OF HOUSTON LIGHTING AND POWER COMPANY FOR AUTHORITY TO CHANGE RATES § DOCKET NOS. 6765 AND 6766

PETITION OF HOUSTON LIGHTING AND POWER COMPANY FOR APPROVAL OF PROPOSED INTERIM ACCOUNTING TREATMENT FOR LIMESTONE UNIT I §

November 14, 1986
On Clarification December 4, 1986
Rehearing Denied December 22, 1986

Houston Lighting and Power Company's application for a general rate increase granted in part and denied in part. $113,024,000 base rate revenue increase granted, as opposed to utility's requested base rate revenue increase of $345,289,000. Reconcilable fuel expense set equal to $1,011,491,278. (Note: there is no Section X in the Examiners' Report, nor Exhibits 2 or 5.)

E. Depreciation and Amortization

Company witness Brian testified that HL&P is requesting $6,862,000 for extraordinary amortization of those charges relating to the cancellation of Allens Creek and the Freestone Projects. (Schedule G-5 at 6, Company Rate Filing Package.) Mr. Brian further noted that the amortization relating to Allens Creek reflects proceeds from equipment sales arising from expenditures prior to January 1, 1980. Although the company still contends that the Commission's regulatory treatment of Allens Creek in Docket No. 4540 was in error, the company only included those amounts allowed under the Commission's order in that case. The company is also requesting amortization of limited term easements in the amount of $16,000 for a total amortization expense of $6,878,000. Mr. Brian testified further that the company is requesting $203,709,000 for depreciation expense. Mr. Brian testified that this amount is based upon a comprehensive study of the company's production, transmission, distribution and general plant accounts conducted by Mr. Gillett.

City accountant Jansen testified that he permitted the amortization expense for Allens Creek alone. Mr. Jansen, accordingly, increased the company's amortization expense by $391,000 to reflect that amount associated with the Freestone Project. (City Exhibit No. 1, Jansen 10 at 4.) (It appears that

Mr. Jansen made a positive adjustment to the company's proposed ($391,000) to the Freestone project. (See Schedule G-5 at 5, Company Rate Filing Package.) There is no explanation for this adjustment in his testimony. The reason for the increase in amortization expense proposed by Mr. Jansen is a mystery left unresolved in the record.) Mr. Jansen, based upon city depreciation witness Lawton's recommendations, proposed a decrease to the company requested depreciation expense in the amount of $14,226,000 for a total allowable depreciation expense of $189,483,000, and a total depreciation and amortization expense of $196,752,000. (City Exhibit No. 1, Jansen Schedule 10 at 1.)

OPC witness Andersen recommended several adjustments to the company's amortization and depreciation expense. As earlier discussed, Dr. Andersen recommended that the excluded plant arising from excess capacity should receive return treatment. Dr. Andersen accordingly increased the amortization expense in the amount of $1,065,000 to reflect this amortized return. Additionally, Dr. Andersen proposed to decrease the company's requested depreciation for gas and other production plant in the amount of $5,961,000, and further recommended a reduction in depreciation expense associated with Limestone 1 of $28,157,000. The recommendation for Limestone is based upon a sinking fund method of depreciation. (OPC Exhibit No. 90A, Schedule 4 at 2.) The total recommended decrease to depreciation and amortization expense is $33,053,000. (OPC Exhibit No. 90A, Schedule 4.)

Staff accountant Young recommended a decrease in the company's depreciation expense in the amount of $35,203,000 based upon depreciation adjustments recommended by Staff Engineer Saathoff and Staff Economist Reilley. Mr. Reilley also proposed a sinking fund depreciation method to compute the company's depreciation expense for Limestone 1. Under Mr. Reilley's method, Limestone 1 would have a depreciation expense of $2,733,091. Mr. Saathoff proposed modifications to the company's gas/oil depreciation rates and coal depreciation rates. As a staff alternative, Mr. Saathoff also proposed a depreciation rate for Limestone 1. Based upon the staff's depreciation rates and the exclusion of the Parish modifications from invested capital, Mr. Young recommended a total depreciation and amortization expense of $175,384,000.

1. Depreciation Rates Other than for Limestone 1

a. <u>Company's Position</u>. Mr. Gillett presented testimony regarding the depreciation rates for the company's production, transmission, distribution and general plant accounts. Mr. Gillett explained that the function of depreciation is to allow the investor an orderly recovery of his investment. Mr. Gillett used the life span method for all the production accounts, including other production, and the simulated plant balances method for the other accounts.

Mr. Gillett testified that the gas and oil fired generating stations do not wear out but pass through transition of usages--as base load, peaking and then reserve units. Five factors were considered in developing depreciation rates for gas/oil-fired production units:

1. the life span of the station,
2. the useful productivity of the station,
3. the impact of subsequent additions and interim retirements,
4. salvage and cost-of-removal, and
5. the adequacy of the reserve.

(Company Exhibit No. 9 at 6.) Mr. Gillett obtained data from the company regarding the production history and projected production for these units. From this data, Mr. Gillett determined the total production from these units and compared that to the theoretical production, as if the unit ran for 8,760 hours a year, to determine its capacity use factor. Mr. Gillett provided the following example to explain his calculation of a capacity use factor:

> For instance, in their sixth year (age interval 5.5) the plants shown produced 45,629,983 megawatt-hours. By dividing the production by the product of connected megawatt capacity at interval 5.5 (8,719,351) and the number of hours in a year (8,760), the composite capacity use factor for all plants in their sixth year was determined to be 59.7 percent.

(Company Exhibit No. 9 at 8.) Mr. Gillett plotted the capacity use factor on a curve and determined a productive service life of 38.7 years. Mr. Gillett rounded this figure to 38 years. Next, Mr. Gillett included interim additions and interim retirements. Both adjustments shorten the average service life because neither survive the entire life of the unit. The interim additions were based upon the company's five year construction budget. Mr. Gillett noted that interim additions were made to gas/oil-fired and coal-fired plants. Furthermore, the interim retirements, net salvage and cost of removal associated with interim retirements were negligible. As to the final cost of removal of plant, Mr. Gillett utilized a 5 percent figure. Mr. Gillett ran schedules to reflect the current depreciation rate of 3.287 percent over a 38-year period and a 5 percent cost of removal and found that in 2012, 8.6 percent or $106,387,000 of the costs would remain unrecovered. Using a 3.751 percent depreciation rate and a 5 percent cost of removal over a 38-year period, the company would recover its total investment. Therefore, Mr. Gillett recommended a depreciation rate of 3.751 percent for the company's gas/oil-fired units.

As to coal-fired generation, Mr. Gillett noted that the company was projecting a 35-year service life. While applying the same analysis as was conducted for gas/oil-fired units, Mr. Gillett foresaw no clear trend; therefore, he relied on the company's projected retirement dates. Mr. Gillett stated that due to pollution control problems uniquely associated with coal plants, interim additions would be more prevalent. Mr. Gillett further believed that a 5 percent cost of removal was appropriate. Utilizing the current depreciation rate of 3.000 percent, a 5 percent cost of removal and a 35-year retirement date would result in a 5.5 percent underrecovery in the approximate amount of $74,464,000. However, under a 3.185 percent depreciation rate, a 5 percent cost of removal and a 35-year retirement date, the company would obtain full recovery.

With regard to the other production accounts which consist of combustion turbines and combined cycle units, Mr. Gillett noted that none of the plants are scheduled for retirement. If kept in service, and recovered at the current depreciation rate of 5 percent, full recovery would be achieved.

As to the other accounts--transmission, distribution and general plant (Company Exhibit No. 9, Exhibit JBG-10)-- Mr. Gillett determined the average service life by the original group method, simulated plant balances method, and actuarial analysis. The simulated plant balances method required development of survivor curves. A survivor curve reflects the group of units which remain at the end of a certain period. The area under the curve divided by the original group provides the average service life of the group. In the original groups method, several original groups were studied to obtain a trend in average service life. The simulated plant balances method entails trial and error to determine the combination of survivor curve and average service life which would produce a plant balance reflective of actual book balances. Another variation of this method, the simulated plant retirement method, attempts through trial and error to reflect a dispersion and service life which best reflects actual book retirements. Mr. Gillett testified that both analyses were performed on the remaining accounts. Upon obtaining the required data, Mr. Gillett conducted a number of various analyses and comparisons to obtain his recommended depreciation rates. (Company Exhibit No. 9 at Schedule JBG-10.)

b. City's Position. Mr. Pous expressed disagreement regarding several areas of Mr. Gillett's depreciation study: interim additions for the gas/oil-fired and coal-fired production plant, treatment of common facilities at production plant sites, service life for other production plant, average service life of mass property accounts, and net salvage for mass property accounts.

Mr. Pous testified that while interim additions shorten the investment's estimated service life, they also increase both depreciation accrual rates and depreciation expense. Mr. Pous further testified that owing to the interim additions proposed by Mr. Gillett, the depreciation for gas/oil-fired units is increased by $277,100,000 and the coal-fired units by $202,300,000 for a total increase of $479,400,000. Mr. Pous found this 23 percent increase to be improper for two reasons. First, while interim retirements are proper, interim additions have been found by the National Association of Regulatory Commissioners (NARUC) to be improper. Mr. Pous cited a portion of a NARUC publication entitled "Public Utility Depreciation Practices" which stated, in part:

> Appropriate computations must be made for such interim retirements, but interim additions are not considered in depreciation computations until they are actually made. . . .
>
> It is possible to estimate the probable future retirements and additions to a particular piece of property and thus arrive at a single depreciation rate applicable over the entire life of the property. This is an unsatisfactory practice inasmuch as considerable speculation would be required to make such an estimate of future additions. . . . This procedure would be further complicated by necessity of forecasting the probable cost level at the time of a future addition. In any event, this is not necessary inasmuch as the depreciation accrual rate can be adjusted in future years as additions are made. (Emphasis added.)

(Id. at 133-134, City Exhibit No. 5 at 7.) Second, Mr. Pous testified that not only are the costs of such additions very speculative in nature, but it is also uncertain whether the additions will be made at all. Mr. Pous recommended exclusion of interim additions from the company's calculation of depreciation rates for gas/oil-fired and coal-fired units.

Mr. Pous also recommended an adjustment to the company's production-related common plant. Mr. Pous noted that due to the company's lack of data on common facilities, the company did not consider the common production plant facilities differently than the other production plant. Mr. Pous recommended that the production common plant facilities be separately considered in determining the overall depreciation rates for gas/oil and coal-fired units. Mr. Pous explained that the estimated service life of common facilities is based upon the first year's operation of the first plant and the retirement date of the last plant retired. Mr. Pous then assigned an estimated service life for the company's common facilities corresponding to the time period between the date the first unit became operational and the date the last unit is projected to be retired of its gas/oil-fired and coal-fired plants.

Mr. Pous concluded that adjusting the company's gas/oil-fired and coal-fired production plants for the exclusion of interim additions and for the common facilities, the depreciation rate for gas/oil-fired production plant would be reduced from .0375 percent to .0317 percent and the depreciation rate for coal-fired production plant from .0319 percent to .0305 percent.

Mr. Pous also recommended a modification to the estimated service life of the company's other production plant. Mr. Pous stated that the depreciation rate for the company's other production plant is based upon a 20-year average service life and a 5 percent depreciation rate. Mr. Pous took exception to Mr. Gillett's statement that the recovery of these assets would occur "within their estimated remaining life." In Mr. Pous' opinion, with a 5 percent depreciation rate, recovery would occur well within the remaining estimated life and thus would result in accelerated depreciation, a method which is not in compliance with the Commission's rules requiring straight-line depreciation. As the basis for his recommendation, Mr. Pous stated that the company had installed the first six other production plants in 1967 with the remaining plants installed during 1968 through 1976. This would indicate that by 1984, the first six plants would have already been in use for 17 years. However, Mr. Pous stated that the company has no plans to retire any of these units until 1996 or later, thereby implying a 30-year service life and not a 20-year service life. While Mr. Pous believed that the company could utilize the plants for 30 years, Mr. Pous utilized the industry average of 25 years to obtain his recommended depreciation rate for other production plant of .0383 percent.

Mr. Pous further recommended changes to the estimated service lives of mass property accounts--transmission, distribution and general plant accounts. Mr. Pous noted that one example of a mass property account is that of a utility's poles. Mr. Pous explained that the company relied on a simulated plant records--balance and retirements (SPR-balance, SPR-retirements)--analysis to determine the estimated service lives of the mass property accounts. Mr. Pous further explained that while such analysis produces survivor curves, not all of the curves are appropriate and reliable. Mr. Pous stated that on many occasions, a stub curve occurs. A stub curve results when a curve produces a survivor level but does not do so completely. Mr. Pous was also concerned with the company's utilization of the SPR-retirements method. In Mr. Pous' opinion, such method may overreact to individual occurrences which may not be representative of the account as a whole. Therefore, Mr. Pous prefers to use the SPR-balance method also proposed by the company because such method is a more stable indicator of estimated service life and corresponding mortality dispersion.

Mr. Pous recommended changes to the estimated service life and resultant mortality dispersion for five mass property accounts. Mr. Pous utilized a 37-year service life and a corresponding S0 Iowa curve for Accounts 353 and 362, Transmission and Distribution Plant Station Equipment. Although the company proposed a 34-year estimated service life, the company's SPR-retirements analysis demonstrated average service lives in the upper 30's or low 40's. Mr. Pous' independent SPR-balance analysis demonstrated service lives of 37 to 39 years, and under the SPR-retirements analysis of 35 to 39 years. For Account 390, General Plant Structures and Improvements, Mr. Pous recommended a 34-year service life and a corresponding S3 survivor curve. While the company proposed a 40-year service life, the analysis of the SPR-retirement analysis showed an average service life of 30 to 36 years and the SPR-balance analysis of 31 to 32 years. For Account 392, Transportation, Mr. Pous recommended a 7-year service life with a corresponding R1 survivor curve. Although the company had proposed a 6-year life, the SPR-balance analysis reflected lives closer to 7 years. The company also performed an actuarial analysis of this account which indicated lives of 7 to 8 years. As to Account 394, Mr. Pous determined that the company's 40-year service life was in error because it was based on a stub survivor curve. Under the company's SPR-retirement analysis, the estimated life was 35 to 38 years. Under the SPR-balance method, the average service life was 31 years. Mr. Pous recommended a 33-year service life with a corresponding S1.5 survivor curve.

Mr. Pous concluded that his recommendations are based not only upon the company's SPR-retirement and -balance analyses, but upon those he himself performed. Mr. Pous placed greater weight in the SPR-balance than retirement method and used different mortality dispersions than that of the company because in many instances, those proposed by the company were predicated on stub survivor curves.

The last area wherein Mr. Pous had specific recommendations was in the area of net salvage value. Net salvage constitutes that portion remaining after deducting the cost of removal from the gross salvage value (from sale or use). The asset to be amortized is either increased or reduced by the positive or negative net salvage value. Mr. Pous recommended changes in the company's net salvage values for various transmission, distribution and general plant accounts. Mr. Pous testified that while the company indicated it determined the net salvage value by reviewing data over a 10-year period, the company did not do so for Accounts 353, 354, 355, 356, 373, 390 and 391. Additionally, Mr. Pous also corrected a mathematical error the company made in Account 362.

Mr. Pous recommended the following adjustments to the company's depreciation rates:

Account No.	Company	City
Production Plant		
311 - 316 - Gas/Oil	3.751%	3.17%
311 - 316 - Coal	3.185%	3.05%
341 - 346 - Other Production	5.000%	3.83%
Transmission Plant		
353 - Station Equipment	2.33%	1.99%[1&2]
354 - Towers and Fixtures	2.62%	2.49%[2]
355 - Poles and Fixtures	6.31%	5.94%[2]
356 - Overhead Conductors and Devices	2.96%	2.86%[2]
Distribution Plant		
362 - Station Equipment	2.29%	1.95%[1&2]
373 - Street Lighting and Signal Systems	3.63%	3.58%[2]
General Plant		
390 - Structures and Improvements	3.21%	2.40%[1&2]
391 - Furniture and Equipment	3.40%	3.06%[2]
392 - Transportation Equipment	12.66%	10.13%[1]
394 - Tools, Shop, Garage Equipment	2.03%	2.54%[1]

[1]Adjusted for service life and mortality dispersion.
[2]Adjusted for net salvage value.

(Company Exhibit No. 9, Exhibit JBG G-10, City Exhibit No. 5, Exhibit JP-1.)

c. OPC's Position. Dr. Andersen presented testimony regarding adjustments to the company's gas/oil-fired production plant and other production plant depreciation rates. As to the gas/oil-fired product plant, Dr. Andersen noted that Mr. Gillett relied solely on historical data. Such basis ignores two factors which would extend the estimated service life of these plants--the decline in gas prices and decline in technological progress. Dr. Andersen explained that with a decline in gas prices, the company should consider the reduction of coal in its generation mix and replace such reduction with gas/oil-fired generation. Moreover, the natural tendency would be to increase the useful life of the company's current gas capacity. Dr. Andersen further testified that owing to the heat rates of gas/oil-fired units which have levelized since the 1960s, there is no longer the economic incentive to retire these gas units since retirement would not lead to the installation of more efficient units.

Dr. Andersen further reviewed the capacity factors of the company's gas-fired units which have been placed in operation within the last 20 years. Dr. Andersen's review reflected three things. First, capacity factors did not decline with the increased age of the units. Second, except for those units over 21 years of age, the projected capacity factors are higher than those utilized by Mr. Gillett in his analysis. Dr. Andersen noted that the difference between the historical age utilized by Mr. Gillett and his projected capacity factors widened with the increase of the age of the units. Third, when the units are grouped by commercial in-service date, no relationship between the age of the unit and the expected capacity factor exists. Dr. Andersen concluded that because a unit's position in the loading order is predicated on its heat rate, and because no causal relationship exists between a unit's heat rate and its age, age cannot be used as the primary basis to determine the life of a unit. Dr. Andersen therefore recommended that the company's current depreciation rate of 3.287 percent remain unchanged.

Dr. Andersen also did not agree with the company's 5 percent depreciation rate for its other production plant. Dr. Andersen found the company's inclusion of T. H. Wharton Units 3 and 4 in other production plant to be inappropriate. Dr. Andersen determined that the capacity factors of T. H. Wharton Units 3 and 4 would extend beyond 1996. The projected capacity factors are not only significantly higher than those of the other production plant but are, moreover, significantly higher than those for the post-1966 gas/oil-fired plants. Dr. Andersen therefore recommended a depreciation rate of .03287 percent for T. H. Wharton Units 3 and 4, which resulted in a composite depreciation rate for the other production plant of .04225 percent. The total recommended decrease to the company's depreciation expense for gas/oil-fired and other production plant is $5,961,000. (OPC Exhibit No. 90A, Schedule 4-1.)

d. Staff's Position. Staff Engineer Saathoff testified as to changes to the company's depreciation rates for its gas/oil-fired and coal-fired production plant. While Mr. Saathoff found the company's depreciation study to comply with generally accepted depreciation theory and practices, Mr. Saathoff had three concerns with the company's proposal. First, although the company does not normally keep books on its individual generating units and thus estimates are used when a unit is retired, Mr. Saathoff noted that the company did maintain a detailed accounting study of the book costs for retirement purposes for Hiram Clark Units 1-4, Green Bayou Units 3 and 4, and Webster Units 1 and 2--all scheduled for retirement in December 1985--as well as Deepwater Units 1-6, the Greens Bayou Units 1 and 2, and T. H. Wharton Unit 1--all scheduled for retirement in 1987. The book value for the 1985 retirements is $54,679,000, and not $65,941,000 as used by the company; the book value for the 1987 retirements is $24,436,000, not $51,721,000.

Second, Mr. Saathoff disagreed with Mr. Gillett's use of interim additions predicated on HL&P's estimated 5-year construction budget. Mr. Saathoff noted that should additions occur, the company can quantify the amount and request its recovery in a subsequent rate case. Mr. Saathoff recommended that the interim additions be excluded owing to their speculative nature, and further recommended that such amounts be excluded from the company's future plant retirements.

Third, Mr. Saathoff disagreed with the company's timing of retirements, which Mr. Gillett assumed to occur in mid-year. Although individual mass accounts such as poles may reasonably be assumed to be retired throughout the year, Mr. Saathoff testified that it was not reasonable to assume the same for generating units. Mr. Saathoff explained that it is a common practice in the industry to retire plants at year end, and moreover, that is exactly the procedure followed by HL&P. Mr. Saathoff therefore recommended that the depreciation rate proposed by the company be adjusted to reflect the actual practice of retirements of units at year end rather than the assumed mid-year retirements. Mr. Saathoff's adjustments to the company's production plant provides the following recommended rates:

Account No. Production Plant	Company	Staff
311 - 316 - Gas/Oil	3.751%	3.02%
311 - 316 - Coal	3.185%	3.02%

e. Examiners' Discussion and Recommendation. Although the city proposed an amortization adjustment to the Freestone Project, no testimony was provided as to the reason for such adjustment. The examiners would note that the staff recommended no adjustment to the company's amortization expense. (Staff Exhibit No. 7 at 33.) The examiners find no basis for the city's adjustment and therefore find the company's amount reasonable. The examiners recommend adoption of $6,878,000 for the company's amortization expense.

The examiners are persuaded that Mr. Saathoff's recommendation of a 3.02 percent depreciation rate for gas/oil-fired and coal-fired production plant is the most reasonable in the record. While overall the examiners find Mr. Gillett's depreciation study to be reasonable, the examiners agree with Mr. Saathoff and Mr. Pous that interim additions should not be included in the calculation of depreciation rates. Such proposed additions are based on a 5-year projected construction budget. The examiners agree with Mr. Pous, who testified that such budgets are subject to change due to company decisions in planning, lack of funds or the change in the status of usage, i.e., from an intermediate to peaking unit. (Tr. at 2084.) Also, as pointed out by the city in its brief, Mr. Gillett's study included a 1985 projected budget of $57,597,000 when the actual additions totaled only $22,165,776, or approximately 39 percent of his projections. (Tr. 576 and 581.) Additionally, the examiners find appropriate Mr. Saathoff's adjustment of the company's plant balances to correct for the timing differences in retirement to reflect the actual retirement practice of HL&P. Moreover, the examiners further find reasonable and necessary Mr. Saathoff's utilization of actual book retirement costs rather than the estimates provided by the company. The examiners would note that Mr. Saathoff's adjustments raised limited cross-examination by the company perhaps owing to the company's concentration on the issue of sinking fund depreciation. Nevertheless, the company apparently had little problem with Mr. Saathoff's recommendations. The examiners find convincing not only Mr. Saathoff's demeanor on cross-examination but note his substantial and lengthy experience in the area of depreciation. The examiners would note that while Dr. Andersen provided testimony which also disproved the validity of Mr. Gillett's depreciation rate for gas/oil-fired units, he did not, as did Mr. Saathoff, conduct a study to determine an appropriate depreciation rate. The examiners therefore recommend adoption of 3.02 percent as the depreciation rate for the company's gas/oil-fired and coal-fired production plants.

The examiners would further recommend adoption of the city's recommended rates for other production plant and mass property accounts. The examiners found Mr. Pous' analysis to be thorough and reasonable. In particular, the examiners find appropriate Mr. Pous' reliance on the company's own data to reflect a 25 rather than 20-year service life for other production plant. While Dr. Andersen also provided an analysis to calculate a depreciation rate for the company's other production plant, the examiners find that Mr. Pous' calculation is more complete and considers more than the one element reflected in Dr. Andersen's analysis--the unit's capacity factor. While Dr. Andersen's calculation merely excluded two units from the calculation of the appropriate depreciation rate for other production plant, Mr. Pous provided a number of reviews and subsequent modifications to the company's proposed figures. The examiners find appropriate Mr. Pous' modifications to the service life and net salvage value for several of the company's mass property accounts. Additionally, Mr. Pous explained his reasoning as to his reliance and distribution of weight as to the company's SPR analysis. The examiners would note that limited cross-examination was conducted on the above issues and such adjustments went unopposed in the company's brief. The examiners therefore recommend the city's depreciation rates for other production, transmission, distribution and general plant accounts referenced in Section VIII.E.1.b. of this report.

The examiners must point out that Mr. Gillett's method of depreciation appears, in part, to be based upon a unit of production approach. The examiners believe that the company has proposed two methods to calculate its depreciation rates; a unit of production method for all of its production plant and an equal life method for its other accounts. (Company Exhibit No. 9 at 5, 11-12.) Dr. Andersen testified during cross-examination that Mr. Gillett's method is implicitly a unit of production approach. (Tr. at 2234-6.) The unit of production approach provides that depreciation is based on the production or output of a unit rather than depreciation being spread equally over the life of an asset. Mr. Saathoff, during cross-examination, provided a simple definition of the unit of production method:

> For example, if you have a power plant and say that it lasts 30 years, if you used the straight line over its life basis, you would basically have a depreciation that will recoup one thirtieth of the investment every year.
>
> In unit of production, you would estimate how many megawatt-hours or kilowatt-hours that unit would produce over its life and divide the total unit investment by that total megawatt-hours output. And then your depreciation would depend on how many megawatt-hours that unit produced during that year.
>
> So it would be an equal amount per megawatt-hour, but the total amount would depend on the amount of megawatt-hours produced during the year.

(Tr. at 2808.)

In an equal life method, grouping of units is based on estimated rather than average service lives. Dispersion curves, or survivor curves, are fitted to each plant account to determine how many units within that account exhibit a certain expected life. Mr. Pous defined dispersion as a means in which to measure the pattern of different frequency of retirements of components of the total amount of a plant before the entire plant itself is retired. (Tr. at 2106.) This method implicitly reflects that all items in a plant, such as poles, are not fully retired at a single point in time. Mr. Saathoff testified that the equal life method is straight-line depreciation. (Tr. at 2758.)

In Docket No. 3716, Application of Southwestern v. Electric Power Company for a Rate Increase, 7 P.U.C. 78 (June 18, 1981), SWEPCO utilized the unit of production approach in estimating service lives. The Commission specifically rejected this approach because it was not straight-line depreciation and thus not in accordance with the Commission's substantive rule on depreciation; but further, the application of such method would increase the depreciation rate and result in accelerated depreciation--more depreciation expense would be recovered over the early life of the asset compared to the asset's later life.

The examiners would note that none of the parties objected to the method utilized by Mr. Gillett in his calculation of depreciation rates for production plant. Moreover, Mr. Saathoff and Mr. Pous agreed with the company's depreciation study aside from their respective adjustments. (Tr. 2884, City Exhibit No. 5 at 4.) What concerns the examiners is first, the Commission's substantive rules require the use of straight-line depreciation, which unit of production arguably is not, and second, the company has not argued a good cause exception to deviate from the general rule. (It is noted that the examiners provide a complete discussion of the Commission's substantive rules on depreciation and the good cause exception in their discussion of sinking fund depreciation.) The examiners find curious, as will be discussed shortly, the company's aggressive battering of the staff's and OPC's utilization of sinking fund depreciation, and such parties' reliance on the good cause exception for their proposed deviation from the Commission's general rule, vis-à-vis the company's own failure to provide information that good cause exists in this case for the deviation the company proposes.

[22] Owing to the fact that the Commission's rules require the use of straight-line depreciation, the examiners would recommend that while adopting the underlying method of the company's depreciation rate for production plant, that this case specifically hold no precedential value either for HL&P or other utilities for several reasons. First, the option left for the Commission should it determine not to adopt the proposed rates is to force the Commission to rely

on the company's old depreciation rates. Such reliance would not be proper. The company was ordered in its last rate case to perform a depreciation study owing to the changes in technology, operation or growth on the the company's system which may have affected the service life of the company's transmission, distribution and general plant accounts. (Docket No. 5779, Examiners' Report at 138.) The failure to adopt Mr. Saathoff's and Mr. Pous' recommended rates, which are based, in part, on Mr. Gillett's study, would require the Commission to maintain the company's current outdated and excessive depreciation rates. Other than those proposed by the city and the staff, there are no other proposed depreciation rates in the record. Second, the concerns expressed by the Commission in Docket No. 3716 that such method would increase depreciation expense is not present in the instant case. With the adjustments proposed by Mr. Saathoff and Mr. Pous, utilizing the company's methodology, the recommended depreciation rates are lower than the company's existing rates. Third, Mr. Pous, who testified on behalf of the city in this case, also argued on behalf of the Texas Municipal League in Docket No. 3716. In that case, Mr. Pous vigorously opposed the use of the unit of production method of depreciation. Could it not be argued that in this particular instance alone, the use of the unit of production method, modified by the parties, is justified?

Thus, while the examiners find reasonable and acceptable the company's equal life method as straight-line depreciation, the examiners deem it important to raise the issue regarding the unit of production depreciation method relating to production plant. Should the Commission find that a unit of production method is indeed utilized by the company and adopted, in part, by the parties, the examiners would recommend that adoption of the unit of production method of depreciation be permitted for this case alone.

2. Depreciation for Limestone 1

a. <u>Company's Position</u>. Because the company has no experience with lignite units, Mr. Gillett recommended that the depreciation rate for coal-fired production be applied to Limestone 1. In Mr. Gillett's opinion, both require significant interim additions and thus are similar. Mr. Gillett therefore recommended a depreciation rate of 3.185 percent for lignite-fired production units.

Mr. Gillett provided testimony regarding his concerns about sinking fund depreciation. Under straight-line depreciation, the value of the asset is recovered over a certain period of time. Under sinking fund depreciation, a series of uniform annual deposits is calculated, which, with accrued interest, equals the original investment at the end of the period. Under the sinking fund method, in the early years of the recovery of the asset, the annual depreciation expense would be lower than under straight-line. However, while the total depreciation expense would remain the same, during the later years of recovery, the depreciation expense would be a good deal greater.

Mr. Gillett noted several problems with the booking of a significant portion of the recovery of depreciation expense in the later life of the investment. First, such shifting of recovery increases the company's total revenue requirement. Mr. Gillett explained that because depreciation expense under the sinking fund method is smaller during the early years of recovery, the reserve will be smaller and thus the rate base and return larger. The total revenue requirement over the life of the asset under sinking fund depreciation is $3,689,038, with a total return of $2,689,038. Under straight-line depreciation, the total revenue requirement is $3,009,812, with a total return of $2,009,812. (Company Exhibit No. 9, Schedule JBG-12.) The return under the sinking fund is approximately 34 percent higher than that produced under straight-line depreciation. Mr. Gillett noted that, generally, use of a sinking fund depreciation method will produce a higher revenue requirement.

Second, use of the sinking fund depreciation method would complicate the calculation of depreciation. Mr. Gillett explained that because sinking fund utilizes the rate of return in its calculation, when a change in the rate of return occurs, the depreciation expense would require modification. Additionally, because the accumulated reserve is also a function of the return, Mr. Gillett believed the depreciation rate would need to be changed.

Third, sinking fund depreciation increases investor risk. Recovery which no longer occurs in a uniform manner increases the possibility of ultimate non-recovery and thus increases investor risk. Mr. Gillett believed this shifting of recovery in the hands of "unknown regulators acting under unknown and political pressure can hardly be called prudent management." (Company Exhibit No. 9 at 21.) Mr. Gillett further testified that creating such a risk will undoubtedly increase the company's cost of capital which will result in increased costs to the ratepayers.

Mr. McClanahan, in rebuttal, testified that sinking fund depreciation would engender negative financial implications for the company. First, in Mr. McClanahan's opinion, sinking fund depreciation would be viewed as a phase-in plan under FASB 71, which could lead to a write-off of the company's plant. Mr. McClanahan focused on the words "and a normal allocation of depreciation and decommissioning costs" found in the definition of "phase-in" in FASB 71. While normal is not defined, in Mr. McClanahan's opinion, normal would refer to the traditional straight-line depreciation. Because sinking fund depreciation would not permit the recovery of the difference between straight-line and sinking fund depreciation over the first 10 years, a substantial portion of Limestone costs would be required to be written off. Such a write-off will adversely affect the company's credit standing and its ability to raise capital. Second, the available cash flow for new construction will be reduced. Under Mr. Reilley's method of sinking fund depreciation, Mr. McClanahan testified that cash flow would be reduced over $60 million in the first 5 years of the plant's life. Third, sinking fund depreciation will increase the revenue requirement of the ratepayers. And fourth, investment risk will increase owing to the deferred recovery of significant amounts of invested capital.

b. <u>OPC's Position</u>. Dr. Andersen proposed the use of sinking fund depreciation to recover the cost of Limestone 1. Sinking fund depreciation provides for the recovery of an asset by allowing the depreciation expense to increase at a predetermined rate over the life of the asset. If the rate of the depreciation expense is set equal to the pre-tax cost of money, Dr. Andersen testified that his depreciation method would in fact levelize the sum of return, taxes and depreciation over time. Dr. Andersen further testified that sinking fund depreciation will track more accurately the benefits and costs of Limestone 1.

Dr. Andersen testified that based upon a 12 percent discount rate, the addition of Limestone 1 to rate base increases the net present value of future revenue requirements by approximately $878 million during the 1986-2020 time frame. Dr. Andersen quickly added that this does not indicate, however, that the company's decision to construct Limestone was imprudent. Because the cost to operate Limestone 1 will exceed the variable cost of gas generation until the year 2000, Dr. Andersen believed that the company's ratepayers would not enjoy the benefits associated with Limestone 1 until after the year 2000. In Dr. Andersen's opinion, sinking fund depreciation can better match the future costs and benefits of Limestone 1.

Dr. Andersen testified that, historically, gas-fired generation was added in smaller increments, and therefore the benefits better tracked the attendant costs. In Dr. Andersen's opinion, there was at that time some logic in adopting straight-line depreciation because the time distribution of costs mirrored the time distribution of benefits. Megawatt-hour generation declined over time as did the revenue requirements. Such is not the case with Limestone 1, whose benefits will increase over time. Dr. Andersen further stated that the system planner determines the appropriate capacity expansion alternative by attempting to minimize the present value of expected future revenue requirements. As long as the ratepayer has a shorter period of expectation than that of the system planner, he will desire the levelization of costs which reduce his current revenue requirement. Dr. Andersen believed that the use of the sinking fund depreciation will harmonize the interests of the planner and that of the ratepayers. For example, if the nominal fixed cost of depreciation in 1986 and 2020 is $.05 per kWh, although the identical amount in both time periods, in real fixed costs, the $.05 in 1986 constitutes a greater sacrifice than the $.05 in 2020.

Dr. Andersen addressed Mr. Gillett's criticism that the total revenue requirement is always higher with the use of a sinking fund depreciation compared to the result obtained under straight-line depreciation. Dr. Andersen agreed that such a proposition is true in terms of nominal dollars. Yet, at a present value basis, because the ratepayer's cost of money will generally exceed the company's cost of money, the ratepayer would prefer the sinking fund depreciation. As to Mr. Gillett's argument that the sinking fund depreciation rate must change each time the Commission sets a new rate of return, Dr. Andersen disagreed. In Dr. Andersen's opinion, no reason exists to adjust the depreciation rate owing to the levelization of the company's revenue requirement. Dr. Andersen recommended that the company's depreciation expense associated with Limestone 1 of $28,490,814 be reduced by $28,157,000 for inclusion of $333,814 for Limestone 1 depreciation expense.

c. Staff's Position. Staff Economist Reilley also recommended the use of sinking fund depreciation, not only for Limestone 1 but for any major addition of utility plant. In Mr. Reilley's opinion, because the value of an asset declines more rapidly as the asset ages, depreciation rates should be greater in the asset's later years. Under straight-line depreciation, the expense is based on the assumption that the asset's value declines in equal increments over its life. Mr. Reilley likened the sinking fund depreciation to a home mortgage where the payments are equal but the components, principal and interest, vary. Mr. Reilley noted that the total recovered depreciation expense remains the same under straight-line or sinking fund depreciation. Mr. Reilley stated that sinking fund depreciation allocates an increasing amount of depreciation to an asset, however, the revenue requirement which, under his method, is the sum of return and depreciation, remains relatively constant throughout the life of an asset.

Like Dr. Andersen, Mr. Reilley perceived straight-line depreciation as a capital recovery measure for large plant additions such as Limestone 1 to be improper for several reasons. First, Mr. Reilley noted that under straight-line depreciation, the early years' revenue requirements are significantly higher than the revenue requirement during the later years. In Mr. Reilley's opinion, one of the major reasons for construction of Limestone 1 was for fuel diversification and price stability. Mr. Reilley perceives the use of straight-line depreciation as incongruous with price stability. Mr. Reilley testified that sinking fund depreciation will result in greater equity between generations of ratepayers and is consistent with capital recovery. Mr. Reilley noted that under his proposal, the revenue requirement would remain relatively level rather than inordinately high at the beginning of an asset's life and then inordinately low at the end of the asset's life.

Second, straight-line depreciation sends inappropriate price signals to the company's ratepayers. Mr. Reilley explained that when a large unit comes into service, the utility will experience overcapacity. Traditional depreciation practices lead to higher revenue requirements in an asset's early years and lower revenue requirements in an asset's later years. Mr. Reilley explained that because the depreciation expense is inordinately high at the beginning of an asset's life, the rate base is larger, which results in a higher cost of service which, in turn, reduces the customers' demand. As an asset ages, less depreciation expense is included in the company's rate base; thus, the cost to serve the customer is decreased which, in turn, increases the customers' demand. In Mr. Reilley's opinion, this is the wrong signal to send consumers because the rise in demand will cause the utility to operate its less efficient units and subsequently construct expensive plants. Mr. Reilley believed that stability in the company's revenue requirement will improve the efficiency of pricing.

Third, Mr. Reilley also viewed straight-line depreciation as a mere accounting procedure and not an appropriate capital recovery mechanism which acts to reflect the true value of the asset. Mr. Reilley noted that, generally, an asset's value decreases much faster in the later years of an asset due to technical and economic obsolescence. This phenomenon is not reflected under straight-line depreciation. In Mr. Reilley's opinion, sinking fund depreciation can act to provide a constant rate of return on book value and is compatible with capital budgeting methods. He noted that capital budgeting techniques rely on the theory that an adequate return on investment must be earned over the life of the asset. In Mr. Reilley's opinion, while achievable under sinking fund depreciation, it is not achievable under straight-line depreciation.

Mr. Reilley, as did Dr. Andersen, did not discount straight-line depreciation entirely but noted that the change in type and size of plants creates the need for a new depreciation method. Mr. Reilley testified that for a while, the utilities were adding generation in smaller increments which reflected the fact that capacity met demand in a somewhat stable manner. Because plant additions are now larger than previously installed plants, the steep increases in cost will continue, thereby rendering the cost of electricity uncompetitively high. (Staff Exhibit No. 8 at 21.)

As to whether or not sinking fund depreciation is a phase-in plan, Mr. Reilley testified that although the result of sinking fund is to lower the revenue requirement in the early years of the plant's operations, it is, in essence, a proper capital recovery method designed to obtain intergenerational equity and efficiency in pricing; it is not a rate moderation plan. Mr. Reilley again noted that not only will HL&P be fully compensated for the cost of the investment but further it will continually earn a return on its investment. As to Mr. Gillett's comment that under sinking fund depreciation the depreciation expense would require modification with each change of the company's rate of return, Mr. Reilley stated that this was not necessary. Mr. Reilley explained that the total revenue requirement, which remains relatively constant, would vary as a function of the return.

While advocating the use of sinking fund depreciation, Mr. Reilley was cognizant of drawbacks in his recommendation. First, the cumulative cost to the ratepayers is greater under sinking fund depreciation than under straight-line depreciation. Mr. Reilley noted that with a rate of return of 11.37 percent for the utility, a 10 percent discount rate for the ratepayer, a 35 year expected life of an asset, and an original investment of $893,128,968, the cost of return and depreciation under sinking fund would be $3,638,151,389 versus $2,721,006,714, under straight-line, for a difference of $917,144,675 in nominal dollars. (Staff Exhibit No. 8, Schedule V.) Mr. Reilley noted that while this difference is closer on a present value basis, if the ratepayers cost of capital is greater than 10 percent, the ratepayer would prefer the use of sinking fund depreciation.

Second, under sinking fund depreciation, the company will experience a reduction in cash flow during the early years of the asset's life . Mr. Reilley stated that the effect of such reduction on the company is dependent upon the size of the investment and need for cash by the utility. Mr. Reilley testified he considered this factor in his financial integrity analysis of HL&P. Mr. Reilley determined that sinking fund depreciation does not significantly adversely affect HL&P's financial condition. Based upon Mr. Reilley's recommended CWIP level of 32 percent of the company's total CWIP balance in rate base, HL&P will not be financially harmed by the reduction in cash flow of $24,000,000 .

Third, the use of sinking fund depreciation adds uncertainty in the capital recovery process. The delay in recovery will affect investors' perceptions. The level of risk will increase as the capital recovery of additional units is delayed. This could result in a higher cost of capital and thus a higher rate of return. Mr. Reilley added that such effect can be mitigated by structuring a definite depreciation schedule and cautioned that future regulators should be discouraged from altering the depreciation schedule which could result in disallowances. Mr. Reilley therefore recommended that the sinking fund depreciation schedule established remain unchanged. Mr. Reilley noted that should the plant be removed from rate base, because a significant amount of recovery under sinking fund depreciation occurs during the later years of an asset's life, the disallowance will fall on the utility and its investors and not its ratepayers.

Fourth, the utility's accounting firm may not perceive sinking fund depreciation to meet generally accepted accounting standards. Mr. Reilley recognized that revisions to the regulatory accounting procedures, i.e., FASB 71, could construe sinking fund depreciation as a phase-in plan which could, in turn, lead to possible write-offs if the phase-in plan is not structured according to the criteria of FASB 71. However, Mr. Reilley testified that sinking fund depreciation is not a "phase-in" technique "per se" and that his recommendation is not predicated upon any notion of rate moderation.

In order to compare estimated revenue requirements associated with sinking fund depreciation and straight-line depreciation for Limestone 1, Mr. Reilley prepared schedules which reflected the capital cost of Limestone 1, return, depreciation, federal income tax, property insurance and franchise taxes. (Staff Exhibit No. 8, Revised Schedule X at 3-6, Examiners Exhibit No. 6.) The revenue requirement under sinking fund depreciation, which remains relatively stable compared to that of straight-line depreciation, is estimated to drop from $173,513,000 in year one to $109,691,000 in year 35, for a total revenue requirement in nominal dollars of $4,295,618,000. Under straight-line depreciation, the revenue requirement is estimated to drop from $197,062,000 in year one to $32,861,000 in year 35, for a total revenue requirement in nominal dollars of $3,375,109,000. The difference in nominal dollars between sinking fund and straight-line depreciation over the 35-year period is $920,509,000.

Based upon the staff's recommended return, 5 percent net salvage value, and plant balance for Limestone 1 of $893,128,968, Mr. Reilley recommended a depreciation expense for Limestone 1 of $2,733,091 or a reduction of $25,757,723 to the company's request for Limestone 1 depreciation expense of $28,490,814. Mr. Reilley believed that no true-up was necessary because if the company underrecovers in depreciation, it can overrecover in return. Mr. Reilley did note, however, that toward the end of the service life of the asset, the problem may become sufficiently severe to warrant a surcharge to ascertain that complete recovery is realized.

In the alternative, the staff recommended that should sinking fund depreciation not be adopted for Limestone 1, the staff-recommended depreciation rate for coal units of 3.02 percent be applied to Limestone 1. (Staff Exhibit No. 3 at 6-7.)

d. Examiners' Discussion and Recommendation. Depreciation has generally been treated as a systematic means of returning investment to a utility. While reimbursing the utility for its investment, both Mr. Reilley and Dr. Andersen urge a different timing of this recovery for policy reasons. Mr. Reilley recommended the use of sinking fund depreciation to promote intergenerational equity and pricing efficiency. Intergenerational equity would correct the disparity which exists under straight-line depreciation wherein the revenue requirement for ratepayers in year one is $197,062,000 compared to the revenue requirement for ratepayers in year 35 of $32,861,000. (Examiners' Exhibit No. 6.) Under sinking fund depreciation, the revenue requirement would remain relatively constant with the return decreasing and depreciation expense increasing from year to year. (Id.) Pricing efficiency would occur because the ratepayers would receive the appropriate price signal that electricity is not becoming less expensive during the later years of a plant's life. Under straight-line depreciation, the decrease in expense causes the relaying of this inaccurate price signal which, in turn, causes increased demand and subsequent construction. Dr. Andersen recommended the use of the sinking fund depreciation because it better reflects the timing of Limestone 1 benefits with its costs. Because, in OPC's opinion, the costs of Limestone 1 will not meet the variable costs of gas production until the year 2000, based in part on a graph presented by Dr. Guy (Company Exhibit No. 14, Guy-Chart 13), the depreciation expense, that is, the return of the company's investment, should reflect this timing of benefits. Both Mr. Reilley and Dr. Andersen, while not discounting the validity of straight-line depreciation for other plant such as transmission or distribution plant, testified that the change in regulatory treatment of depreciation expense should occur with Limestone 1. As both Mr. Reilley and Dr. Andersen stated, straight-line depreciation was appropriate when generation was added in fairly small and steady increments. Thus, both OPC and staff are urging policy considerations which require the change in depreciation method for Limestone 1. In that regard, both Mr. Reilley and Dr. Andersen advocate the utilization of a sinking fund depreciation for all future major plant additions. (Staff Exhibit No. 8 at 17, Tr. at 2256-7.)

While the examiners note merit in the application of sinking fund depreciation to Limestone 1, they further note that its adoption must be consistent with this Commission's substantive rules. Both the company and the city point to the Commission's substantive rules which stand as a barrier to the adoption of sinking fund depreciation.

Under P.U.C. SUBST. R. 23.21(b)(1)(B), allowable expenses include depreciation which is to be computed as follows:

> (B) Depreciation expense based on original cost and computed on a straight-line basis as approved by the Commission.

In determining the company's rate base, the Commission determines the company's original cost and accumulated depreciation. P.U.C. SUBST. R. 23.21(c)(2)(A) states:

> (A) Original cost, less accumulated depreciation, of utility plant used by and useful to the public utility in providing service.
>
> > (i) Original cost shall be the actual money cost, or the actual money value of any consideration paid other than money, of the property at the time it shall have been dedicated to public use, whether by the utility which is the present owner or by a predecessor.

> (ii) Reserve for depreciation is the accumulation of recognized allocations of original cost, representing recovery of initial investment, over the estimated useful life of the asset. Depreciation shall be computed on a straight-line basis over the expected useful life of the item or facility. (Emphasis added.)

Both the city and company argue in brief that the Commission's rules are clear on their face and thus straight-line depreciation must be utilized. The company and city further cite State v. Martin, 247 S.W.2d 809 (Tex. Civ. App.--Austin 1961, writ. ref'd. n.r.e.) for the proposition that an agency is bound by its own rules. Further, both the company and city point to the Administrative Procedure and Texas Register Act (APTRA), Tex. Rev. Civ. Stat. Ann. art. 6252-13a (Vernon Supp. 1986) which prohibits the Commission from abandoning the use of or from modifying its rules without first complying with the requisite procedures for notice and hearing under Section 13(a) of APTRA.

The general counsel and OPC pointed out in their respective briefs that P.U.C. SUBST. R. 23.2, the severability clause, provides the Commission the legal authority to adopt the sinking fund method of depreciation for good cause. This substantive rule states:

> The adoption of this chapter will in no way preclude the Public Utility Commission from altering or amending them in whole or in part, or from requiring any other or additional service, equipment, facility, or standard, either upon complaint or upon its own motion or upon application of any utility. Furthermore, this chapter will not relieve in any way a utility or customer from any of its duties under the laws of this state or the United States. If any provision of this chapter is held invalid, such invalidity shall not affect other provisions or applications of this chapter which can be given effect without the invalid provision or application, and to this end, the provisions of this chapter are declared to be severable. This chapter shall not be construed so as to enlarge, diminish, modify, or alter the jurisdiction, powers, or authority of the commission or the substantive rights of any person. The commission may make exceptions to this chapter for good cause. (Emphasis added.)

The general counsel further argued the following to support her contention that adoption of sinking fund depreciation would be in accordance with the Commission's rules. First, the general counsel argued that the Commission's substantive rules must be read as a whole. Although the Commission has a specific rule requiring the calculation of depreciation on a straight-line basis, it also has adopted a good cause exception to its rule. Second, the general counsel argued that the Martin case which cited Tex. Jur.2d, Administrative Law, further stated, "Although the agency may create exceptions to its rules, the exceptions must not be arbitrary or such as to constitute an unreasonable discrimination." (Id. at 347.) The general counsel urged that for the reasons announced by Mr. Reilley and Dr. Andersen, good cause exists to grant an exception to the Commission's general depreciation rule. Third, as to the city's argument that due process requires that notice and hearing be provided, the general counsel believed that more notice and opportunity to participate existed in the instant case than would be available to the parties in a rulemaking proceeding. (General Counsel's Reply Brief at 7.)

The examiners agree with the general counsel that the Commission's rules must be reviewed in their entirety. While the Commission has adopted a rule which addresses the use of straight-line depreciation, it has also adopted a rule which provides for deviation from its rules for good cause. As the general counsel pointed out, this Commission has permitted deviation from the depreciation rule itself in a previous docket. In Docket No. 4207, Application of San Miguel Electric Cooperative, Inc. for Deferral of Depreciation Expense, (December 22, 1981), this Commission granted the cooperative an exception for its depreciation treatment which deviated from the straight-line method. The cooperative requested approval to defer a portion of its recovery of depreciation expense for a 2-year period in order to mitigate the impact of increased demand costs on low load factor customers. (Id. at 668.) While the city argued that in Docket No. 1517, Application of Texas Power and Light Company for Authority to Change Rates and Inquiry by Public Utility Commission of Texas into Certain Affiliated Transaction of Texas Electric Service Company, Texas Power and Light, and Dallas Power and Light Company, 4 P.U.C. BULL. 1406, (April 20, 1979) and Docket No. 3716, Application of Southwestern Electric Power Company for a Rate Increase, 7 P.U.C. BULL 78 (June 18, 1981) the Commission rejected the abandonment of straight-line depreciation, the examiners would note that in both instances, the effect of the utility's request was one of accelerated depreciation rather than deferral of recovery. The examiners therefore believe that the Commission has allowed for a deferral of depreciation expense as an exception to its general rule based upon a showing of good cause.

[23] The examiners would further note that the election to proceed by rulemaking or by adjudicatory proceeding is a discretionary determination to be made by the administrative body. In State Board of Insurance v. Deffenbach, 631 S.W.2d 794, (Tex. App.--Austin 1982, writ. ref'd. n.r.e.) the Appellate Court determined that an agency can determine to act either by adjudication or rulemaking. In that case, the court found that the agency's decision to act by rule in lieu of adjudication was proper in that the agency's actions were necessarily implied from its duties and obligations. Two distinctions arise from that case and the instant case. First, the Commission has not enacted a rule, but rather, OPC and the staff request such change from the Commission's general rule in an adjudicated hearing. Second, the Commission's duty to set a depreciation method is not implied but expressly required pursuant to Section 27(b) of the Act. Nevertheless, the decision in the case is still appropriate--an agency can decide to proceed by general rule or ad hoc adjudication. The Texas Appellate Court cited SEC v. Chenery Corp., 332 U.S. 194, 67 S.Ct. 1573, 91 L.Ed. 1995 (1947) for the very proposition.

In the Chenery case, the U.S. Supreme Court noted that a certain amount of discretion is necessary in administrative proceedings. The U.S. Supreme Court added that while the administrative agency, in this case, the SEC, could enact general rules, "any rigid requirement to that effect would make the administrative process inflexible and incapable of dealing with many of the specialized problems which arise." (Id. at 202, 1580.) In that regard, the U.S. Supreme Court further stated:

> Not every principle essential to the effective administration of a statute can or should be cast immediately into the mold of a general rule. Some principles must await their own development, while others must be adjusted to meet particular, unforeseeable situations. In performing its important functions in these respects, therefore, an administrative agency must be equipped to act either by general rule or by individual order. To insist upon one form of action to the exclusion of the other is to exalt form over necessity.

In other words, problems may arise in a case which the administrative agency could not reasonably foresee, problems which must be solved despite the absence of a relevant general rule. Or the agency may not have had sufficient experience with a particular problem to warrant rigidifying its tentative judgment into a hard and fast rule. Or the problem may be so specialized and varying in nature as to be impossible of capture within the boundaries of a general rule. In those situations, the agency must retain power to deal with the problems on a case-to-case basis if the administrative process is to be effective. There is thus a very definite place for the case-by-case evolution of statutory standards. And the choice made between proceeding by general rule or by individual, ad hoc litigation is one that lies primarily in the informed discretion of the administrative agency. See Columbia Broadcasting System v. United States, 316 U.S. 407, 421, 62 S.Ct. 1194, 1202, 86 L.Ed. 1563.

(Id. 202-3, 1580, Emphasis added.) More importantly, the U.S. Supreme Court rejected the contention that an agency must proceed to rulemaking if standards have previously been announced. In NLRB v. Bell Aerospace Co. Div. of Textron Inc., 416 U.S. 267, 94 S.Ct. 1757, 40 L.Ed. 134 (1974), the U.S. Supreme Court cited its decision in the Chenery case that even if a general rule exists, the agency is not bound to pursue a change through rulemaking proceedings. In the Bell Aerospace case, the U.S. Supreme Court determined that the NLRB was not precluded from announcing new principles in a proceeding. In that case, the U.S. Supreme Court held that the Board was free to construe differently the definition of "managerial employees" who are as referenced under the Taft-Hartley Act even though the Board's change of position in the Bell Aerospace case was inconsistent with its earlier practice. More importantly, the U.S. Supreme Court stated that a change in standards was not required to be undertaken in a rulemaking proceeding. In that regard, the U.S. Supreme Court cited its decision in the Chenery case:

A similar issue was presented to this Court in its second decision in SEC v. Chenery Corp., 332 U.S. 194, 67 S.Ct. 1575, 91 L.Ed. 1995 (1947) (Chenery II). There, the respondent corporation argued that in an adjudicative proceeding the Commission could not apply a general standard that it had formulated for the first time in that proceeding. Rather, the Commission was required to resort instead to its rulemaking procedures if it desired to promulgate a new standard that would govern future conduct. In rejecting this contention, the Court first noted that the Commission had a statutory duty to decide the issue at hand in light of the proper standards and that this duty remained "regardless of whether those standards previously had been spelled out in a general rule or regulation." Id., at 201, 67 S.Ct., at 1580. (Emphasis added.)

(Id. at 291-2, 1770-1771.)

The choice to proceed by rulemaking or by adjudication is a discretionary decision to remain with the agency.

The examiners fully agree with the U.S. Supreme Court's reasoning. Administrative agencies must be provided a certain degree of flexibility to determine under what circumstances an issue should be resolved under rulemaking or under adjudication. The decision, of course, whether to resolve a particular issue by rulemaking or adjudication is a discretionary matter to be decided by the agency. Thus, the examiners would find that this Commission does have the authority to determine the issue of sinking fund depreciation by adjudication rather than by rulemaking if it so chooses; the question is whether this Commission should so choose.

[24] While the examiners find that the Commission can exercise its discretion to adopt sinking fund depreciation under the good cause exception should it so choose, the examiners cannot find that such choice is appropriate. As noted earlier, both Dr. Andersen and Mr. Reilley are recommending that sinking fund depreciation be utilized for major plant additions. Thus, while the general counsel and OPC argue a good cause exception, they are in reality requesting a major rule change which would become the norm rather than the exception. When such a change in policy has far reaching consequences for other utilities, the examiners believe it is more appropriate to proceed by rulemaking rather than by adjudicatory hearing to formulate policy. The examiners note that the Texas Appellate Court in Deffenbach recognized the usefulness of a rulemaking proceeding when the agency is faced with an action which would affect more than a limited group of persons. The Appellate Court stated:

In cases wherein it appears many persons will be affected in substantially the same manner by administrative action, there are

> advantages in the agency's utilization of rulemaking procedures. Conversely, where a single party or only a small, well-defined group will be affected by the administrative order, the adoption of rulemaking procedures may cause hardships to the parties involved. 1 F. Cooper, State Administrate Law 179 (1965). Unless mandated by statute, the choice by an agency to proceed by general rule or by <u>ad hoc</u> adjudication is one that lies primarily in the informed discretion of the agency. SEC v. Chenery Corp., 332 U.S. 194, 67 S.Ct. 1575, 91 L.Ed. 1995 (1947). Professor Cooper suggests that where an agency faces the alternative of proceeding by rulemaking or by adjudication, the process of rulemaking should be utilized except in those cases where there is a danger that its use would frustrate the effective accomplishment of the agency's functions. 1 F. Cooper, supra, at 181.

(<u>Id</u>. at 7991.)

Thus, while the examiners find some merit in the parties' arguments advocating the use of sinking fund depreciation, the examiners find they cannot recommend its adoption by this Commission owing to the fact that far reaching policy decisions are more appropriately suited for resolution in a rulemaking proceeding than adjudicative hearing. With the numerous major plants coming into service, a rule change or amendment thereto in a timely fashion would be preferable.

However, should the Commission determine to proceed in an adjudicatory proceeding to establish policy, the examiners do not believe that sufficient good cause exists to adopt sinking fund depreciation. The examiners will discuss the major concerns raised by the parties regarding the use of sinking fund depreciation.

First, both the company and the city in their respective briefs point out that the overall revenue requirement is greater under the sinking fund method than under the straight-line method of depreciation. As is evident from Examiners' Exhibit No. 6, the total revenue requirement under sinking fund depreciation exceeds that produced under straight-line depreciation by $920,509,000. Moreover, the cross-over point for revenue requirement, that point where straight-line depreciation would approximate sinking fund depreciation, would be at year nine. After year nine, the total revenue requirement under sinking fund depreciation would consistently exceed that amount reflected under straight-line depreciation. While both Dr. Andersen and Mr. Reilley testified on cross-examination that depreciation expense is only one component of the revenue requirement and that, moreover, the revenue requirement remains relatively stable under sinking fund depreciation, the examiners are still confronted with an increase over the life of the plant in the total revenue requirement of over $920 million. Even Mr. Reilley noted that this factor was a drawback with the application of sinking fund depreciation. (Staff Exhibit No. 8 at 26.) The examiners, while cognizant of the staff's and OPC's valid policy considerations, do not believe these policy considerations outweigh the additional costs imposed on the company's ratepayers.

Second, the choice of the appropriate discount rate, the opportunity cost or ratepayer's cost to borrow money (Tr. at 2907), also poses a concern. Both Dr. Andersen and Mr. Reilley proposed the sinking fund depreciation method but with subtle but distinct variances. Dr. Andersen utilized the company's requested rate of return, including federal tax effects, to compute the implicit interest rate used in the calculation of sinking fund depreciation of 19.3 percent. (Tr. at 2961-2, 3097-8.) Dr. Andersen therefore levelized the sum of return, income taxes and depreciation. (Tr. at 2340-2341 and 3098.) On the other hand, Mr. Reilley utilized the staff recommended return, without any tax implications, to levelize the sum of depreciation and return alone. (Tr. at 2340-1, 2961-62, 3097-8.) As both Dr. Andersen and Mr. Reilley explained, although advocating the same underlying method, the difference in their methods arises from the objectives chosen--the levelization of return, taxes and depreciation or return and depreciation alone. The higher the interest rate, the lower the first years' depreciation expense, however, with a resultant higher expense in the asset's latter years. For example, under Dr. Andersen's schedule, with an implicit rate of 19.3 percent, the first year's depreciation accrual is approximately $500,000 compared to Mr. Reilley's, who utilized a 11.37 factor for a depreciation accrual of $2 million. Yet, at year 35, Dr. Anderson's accrual would be approximately $142 million while Mr. Reilley's would be approximately $98 million. (Tr. at 3099, Staff Exhibit No. 8, Revised Schedule X at 5 of 7.) Because sinking fund depreciation is based on the objective to be attained, the examiners view the selection of an appropriate rate to utilize in the computation of the depreciation expense as a policy decision. In the examiners' opinion, the staff's objective mitigates the disparity in the recovery of depreciation expense over the years. The examiners cannot agree that the company's utilization of Limestone 1 is so insignificant to postpone the recovery to the extent advocated by Dr. Andersen. Thus, if any sinking fund methodology were to be adopted, the examiners would encourage the utilization of the staff's method.

Third, during the first years of sinking fund depreciation, the utility will experience a shortage in cash flow. While OPC argued in brief that such shortfall should be disregarded because the funds are needed to meet STP construction expenditures and to finance new subsidiaries (OPC Brief at 63), the examiners do not find OPC's arguments to be persuasive. Rather, the examiners rely on the staff's analysis that the company's financial integrity will not be significantly adversely affected by this shortfall. (Staff Exhibit No. 8 at 26-7.) The examiners find that the adoption of sinking fund depreciation would not substantially harm the company's financial integrity.

Fourth, the adoption of sinking fund depreciation can affect investors' perceived risk. The company took exception to the adoption of sinking fund depreciation because of the increased financial and investor risk associated with delayed recovery. (Company Exhibit No. 45 at 2, 5-6.) Mr. Reilley agreed that indeed the delay in recovery could be perceived as risky. (Staff Exhibit No. 8 at 27.) In that regard, Mr. Reilley testified that not only should future regulators be discouraged from altering the sinking fund depreciation schedule, if adopted, and thus recommended that once established, it not be changed, but moreover, the rate of return for HL&P would ultimately increase owing to the increased financial risk. As Mr. Reilley explained, under straight-line depreciation, the risk of non-recovery is not as great as that associated with sinking fund depreciation where the recovery is delayed until the plant's later years. In Mr. Reilley's opinion, should sinking fund depreciation be adopted, it will implicitly lead to a higher rate of return. (Tr. at 3100-1.) While the examiners agree with Mr. Reilley's premise that the company's cost of capital will probably increase owing to the adoption of a method of recovery which introduces risk in the timing of recovery, the question before the Commission is whether the increased return attendant to such increased risk should be accepted.

Although the policy arguments of OPC and the general counsel have merit, they are not sufficient, in the examiners' opinion, to overcome the increased expense associated with sinking fund depreciation which will befall the company's ratepayers. While adoption of sinking fund depreciation will inure to the benefits of the company's current ratepayers in that lower revenue requirements will be produced, that will not be the case regarding the company's future ratepayers. As the city pointed out in its brief, should the plant be cancelled in year 31, under straight-line depreciation, over 88 percent of the plant would be depreciated, however, under Dr. Andersen's method, less than 50 percent of the plant would be depreciated. (OPC Exhibit No. 88, Schedule SA-1.) Under Mr. Reilley's method, approximately 78 percent of the plant would be undepreciated at year 31. (Examiners' Exhibit No. 6.) While the parties have argued whether or not such "what ifs" should be determinative or discarded in reviewing the acceptability of sinking fund depreciation, the examiners do not discount or place prime importance on this factor but rather consider it among the other factors to be reviewed in determining the propriety of sinking fund depreciation. In the examiners' opinion, the increase implicitly required in the company's return and the recovery of a significant portion of the company's plant in its later life is not appropriate. The risk of reimbursement for an asset which may not be in service has been shifted to the company's future ratepayers who may not benefit from Limestone 1. More importantly, 30 years hence is too prospective for any individual to guesstimate as to what will occur. Who would have imagined 5 years ago that gas prices would have fallen as they have in the recent past? The examiners choose not to place the risk of recovery with the company's future ratepayers.

Fifth, not only will sinking fund depreciation itself cause increased investor perception of risk, the company also argued that financial risk would occur due to a possible write-off of Limestone costs. As discussed by Mr. McClanahan, FASB 71 requires that deferrals resulting from phase-in's be fully recovered within a 10-year period. If not fully recovered, Mr. McClanahan believed that the difference between that amount recoverable under straight-line and sinking fund over the first 10 years would be written off. The examiners cannot agree with Mr. McClanahan's opinion. As pointed out by Dr. Andersen, Mr. Reilley, Ms. Paton, Mr. Young and even Mr. McClanahan himself, the status of FASB 71 is not yet certain. To date, the final version of FASB 71 to be adopted and the date of such adoption has not even been set. Moreover, as Mr. Brian testified on cross-examination, the company's auditors, Deloitte, Haskins and Sells, have filed comments regarding the ambiguity of the language in the statement, particularly with regard to the word "normal" as it is used in the statement's definition of "phase-in." More importantly, as pointed out both by Mr. Reilley and Dr. Andersen, the statement provides no clear indication that sinking fund depreciation is either "abnormal" or that it is a phase-in plan.

Sixth, as repeatedly testified by both Dr. Andersen and Mr. Reilley, they did not propose the use of the sinking fund depreciation for Limestone 1 based upon any rate moderation theory. (Tr. at 2197-8, 2900-2901, 3091, Staff Exhibit No. 8 at 28.) The examiners would note that sinking fund depreciation could apparently be utilized as a component of a phase-in plan but that in and of itself, it was not proposed as such. Although a fine distinction, it is one that the examiners note does exist. In that regard, FASB 71 specifically addresses accounting treatment for phase-in plans. If not advocated as such by the parties, the examiners are hard pressed to understand the insistence of the company that such plan is indeed a rate moderation plan. The examiners would be more persuaded if the proposal for use of sinking fund depreciation was coupled with a singular and unique treatment for the Limestone 1 production plant itself, that indeed, the mere calling sinking fund depreciation a capital cost recovery mechanism could not disguise the true fact that the treatment is related to rate moderation. However, both OPC and the staff permitted Limestone 1 in the company's rate base without any discussion as to moderating the effect of such plant inclusion. Surely if OPC and staff were concerned with rate moderation in this case, they would have proposed an alternative treatment for the approximate $800 million associated with Limestone 1. In the examiners' opinion, a write-off pursuant to FASB 71 is far from certain because it is not clear that sinking fund depreciation is indeed a phase-in plan.

Lastly, the examiners are not persuaded that financial accounting should dictate regulatory accounting treatment. Thus, the examiners are not convinced that the exposure draft associated with FASB 71 would pose a significant problem regarding the adoption of sinking fund depreciation, should the Commission choose to do so.

In summary, the examiners find that good cause to deviate from the application of straight line depreciation to Limestone 1 does not exist for the following reasons. First, the adoption of sinking fund depreciation will increase the overall revenue requirement of the company. The policy arguments of OPC and the staff do not outweigh the almost $1 billion in additional cost to be born by the company's ratepayers. Second, the examiners are concerned with Mr. Reilley's statement that a surcharge might well be necessary in order to ascertain that the company achieves full recovery. The examiners query whether such surcharge would accompany any application of sinking fund depreciation. Third, Section 27(b) of the Act requires this Commission to set forth a method of depreciation. While the Commission has chosen to do so in a general rule, for consistency, although not required, the Commission may wish to proceed to another rule to set out alternative methods of depreciation. Fourth, as the examiners expressed earlier, the examiners are concerned with the increase in the company's rate of return owing to the perceived financial risk from the use of sinking fund depreciation. The examiners have not been persuaded that the benefits of sinking fund warrant an undoubted increase in the company's rate of return.

3. Summary

The examiners recommend that $16,000 of limited easement amortization and $6,862,000 relating to amortization of the Allen's Creek and Freestone projects be included in the company's depreciation and amortization expense. The examiners further recommend that the company's depreciation study be adopted for this case alone as modified by the examiners in Section VII.E.1. of this report. The examiners further recommend the use of a depreciation rate of 3.02 percent for Limestone 1 and would recommend against adoption of sinking fund depreciation in this case for the reasons discussed above.

The examiners recommend depreciation expense of $195,306,000 in the following amounts for the company's various accounts:

Production Plant	$ 86,871,000
Other Production	7,729,000
Transmission	12,999,000
Distribution	67,334,000
General	20,373,000
Total Depreciation Expense	$195,306,000

The above amounts are calculated as reflected in Examiners' Exhibit No. 7, which is based upon City Exhibit No. 1, Schedule Jansen-10, Pages 2 of 4 and 3 of 4. The total recommended depreciation and amortization expense is $202,184,000. The examiners would encourage the parties to review the examiners' calculation of depreciation and run their own schedules to be filed with their exceptions should the examiners have inaccurately reflected the depreciation expense based upon their recommendations.

F. Other Taxes

The company proposed inclusion of $156,693,000 for other taxes expense composed of the following:

Federal Taxes:	
Social Security	$17,963,000
Unemployment	455,000
State and Local Taxes:	
Ad Valorem	77,545,000
Gross Receipts	35,606,000
Public Utility Assessment	5,308,000
State Franchise	18,771,000
State Unemployment	456,000
Use Tax	588,000

(Schedule G-8 at 1, Company Rate Filing Package.)

The city, OPC and staff proposed a number of adjustments to the company's proposed request.

1. Ad Valorem Taxes

a. City's, OPC's and Staff's Positions. Mr. Jansen recommended a reduction of $79,000 to the company's ad valorem tax expense owing to the city's reduction in the company's plant held for future use and plant in service figure. Mr. Jansen recommended an ad valorem tax expense of $77,466,000.

Ms. Paton reduced the company's request by $1,261,000 and Mr. Young by $229,000 for the same reasons as Mr. Jansen.

b. Examiners' Discussion and Recommendation. The examiners find that the company's effective tax rate of 1.31 percent is reasonable. (Schedule G-8 at 3, Company Rate Filing Package). Applied to the examiners' recommended plant in service and plant held for future use figure of $5,800,486,000 provides a total ad valorem tax expense of $75,986,366.

2. Payroll Taxes

a. Staff's Position. Mr. Young calculated the payroll taxes for the company in a uniform manner. First, Mr. Young calculated a ratio of salaries and wages subject to FUTA tax to total salaries and wages. Second, Mr. Young multiplied this ratio by the staff recommended payroll amount to derive a salary and wage level subject to FUTA taxes. Third, Mr. Young then multiplied this amount by the 1986 FUTA tax rate to obtain a total 1986 FUTA tax cost. Fourth, Mr. Young multiplied the total FUTA tax cost by the test year percentage of payroll charged to expense (63.49 percent) instead of the company-employed FUTA expense factor (69.43 percent). In Mr. Young's opinion, the FUTA tax expense factor did not appropriately track the percentage of payroll expensed. Mr. Young's calculation resulted in a $29,000 decrease to the company's test year expense or a $6,000 increase to the company's request.

As to FICA taxes, Mr. Young used the same methodology as above multiplied by the 1986 effective tax rate of 7.15 percent to obtain a $541,000 decrease to the company's test year expense and a $1,779,000 decrease to the company's request.

Mr. Young utilized the same methodology to determine the company's SUTA tax expense. Mr. Young's calculation resulted in $22,000 increase to test year expense and a $63,000 increase to the company's request.

The staff's total adjustment to payroll taxes is a reduction of $1,710,000 to the company's request of $18,874,000 for a total for payroll tax expense of $17,164,000.

b. City's Position. While Mr. Jansen found the company's FUTA rate appropriate, he agreed with the staff's use of a 63.49 percent expense factor applied to the city's recommended salary level.

Mr. Jansen recommended the same methodology for the FICA and SUTA taxes. Mr. Jansen recommended, based on the city's salary level, a reduction in payroll taxes of $1,877,000.

c. Examiners' Discussion and Recommendation. The examiners would note that the company did not object to the staff's proposed method to calculate payroll taxes. The examiners agree with the staff that the payroll expense factor should be utilized since FUTA, FICA and SUTA are payroll-related items. The examiners recommend adoption of Mr. Young's figures for a total reduction of $1,710,000 to the company's request of $18,874,000, for a total payroll expense of $17,164,000.

3. Other Taxes

a. City's and Staff's Positions. City witness Jansen made one adjustment to the company-requested level for other taxes of $19,359,000. Mr. Jansen reduced the sales use tax by $588,000, due to the non-recurring nature of this amount, for the audited period 1976 to 1983. Mr. Jansen's total adjustment of $640,000 reduced the company's other tax expense to $18,771,000.

Mr. Young recalculated the company's franchise fee requirement utilizing the March 31, 1986 capital structure proposed by Mr. Reed, which included the deferred investment tax credit balance and reserve balances as of March 31,

1986. Mr. Young's calculation reduces the company's request by $23,000 for a total of $19,336,000 to be included as other taxes.

b. Examiners' Discussion and Recommendation. The examiners find Mr. Reed's methodology the most appropriate because it captures the then most current information. Additionally, over no objection by the company, the examiners recommend adoption of Mr. Jansen's deduction of $588,000 relating to sales use taxes. The examiners further recommend that the capital structure recommended in Section VII.B.5. of this report be utilized to recalculate the company's franchise tax requirement to be included in the company's level of other taxes.

4. P.U.C. Gross Receipts Assessment

The examiners recommend application of the staff-recommended effective tax rate of .001618 to the examiners' recommended revenue requirement to determine the P.U.C. gross receipts assessment.

5. State Gross Receipts Tax

The examiners recommend application of the staff-recommended effective tax rate of .010283 to the examiners' recommended revenue requirement to determine the state gross receipts tax.

6. Local Gross Receipts Tax

The examiners recommend application of the staff-recommended effective tax rate of .023142 to the examiners' revenue requirement to determine the local gross receipts tax.

G. Interest on Customer Deposits

The company requested interest on customer deposits in the amount of $2,302,000 to be included in its cost of service. No party opposed such request and the examiners recommend its approval.

H. Federal Income Taxes (FIT)

1. Company's Position.

The company requested recovery of $339,996,000 in federal income taxes. Mr. Brian testified that tax depreciation was determined by multiplying the tax basis property by the company-recommended composite book depreciation rate of 3.76 percent. The 3.76 percent figure was also used to recompute amortization of investment tax credits. Mr. Brian noted further that HL&P files a consolidated tax return. However, Mr. Brian testified that HL&P records as its current federal income tax expense an amount equal to tax as if it filed a separate return.

2. City's Position.

Mr. Jansen utilized the city-recommended revenue requirement with several adjustments to calculate the company's FIT expense. First, Mr. Jansen recommended a recalculation of the interest expense utilizing Ms. Elliott's recommended weighted cost of debt. Second, Mr. Jansen recalculated the company's depreciation addback. To normalize taxes, Mr. Jansen explained that it is necessary to consider 100 percent of the total tax basis and not the 50 percent calculated by HL&P. Mr. Jansen explained that the additional depreciation adjustment must be made to recognize items which were expensed for tax purposes and included in the calculation of FIT for regulatory purposes, but were capitalized for financial purposes. Thus, these figures must be included to normalize taxes. Mr. Jansen stated that the taxable income is multiplied by 46 percent to obtain the taxable amount from which investment tax credits and consolidated tax savings must be deducted. Owing to a lower composite depreciation rate, Mr. Jansen reduced the investment tax credits. Third, Mr. Jansen computed consolidated tax savings enjoyed by HL&P arising from the consolidated filing. In Mr. Jansen's opinion, Section 41(c)(2) of the Act requires that HL&P's fair share of such savings should flow to the ratepayers. Mr. Jansen stated that he calculated HL&P's fair share as 90 percent. On cross-examination Mr. Jansen explained that while 75 percent of the HII management expenses should flow to the company's ratepayers, at the time HL&P incurred the tax savings arising from the consolidated tax filing, HL&P was allocated 90 percent. Mr. Jansen reduced the company's FIT by $65,507,000 for a total FIT expense of $274,489,000.

3. OPC's Position.

Ms. Paton calculated the company's interest expense for tax purposes by multiplying OPC's recommended invested capital times the OPC-recommended weighted cost of debt which increases the company's requested interest expense by $12,573,000. In Ms. Paton's opinion, this adjustment, known as interest synchronization, properly considers the additional interest expense which the company would have incurred but for the availability of investment tax credits. Ms. Paton cited a recent IRS regulation which states that such treatment would not constitute a reduction in the company's rate base. (OPC Exhibit No. 90 at 26).

Additionally, Ms. Paton adjusted the company's amortization of investment tax credits to reflect one-year's amortization of ITC's related to Limestone 1. Ms. Paton believed such treatment is consistent with the company's proposal to annualize O&M expenses and property taxes associated with Limestone 1. Lastly, Ms. Paton recommended that HL&P utilize a 8 percent ITC rather than 10 percent ITC. The company apparently uses the 10 percent ITC to obtain greater cash flow. Ms. Paton explained that should the Commission adopt such modification, the adjustment will affect accumulated investment tax credits, ITC amortization and accumulated deferred taxes.

4. Staff's Position.

The staff, as the company, calculated FIT as a derivation of return. Ms. Keever explained that the return represents that amount necessary for the company to recover its debt costs and provide an after tax return on equity. Ms. Keever took the staff's recommended return less interest and ITC amortization together with adjustments for permanent and non-normalized timing differences to provide an after tax income which is grossed up to compute the taxable income. The taxable income is then multiplied by the FIT rate of

46 percent and is further reduced by investment tax credits to obtain the appropriate level of FIT expense.

In calculating the FIT tax using the aforementioned method, Ms. Keever made a number of adjustments. First, Ms. Keever calculated the interest expense by multiplying the staff recommended rate base times the staff recommended weighted cost of debt. In Ms. Keever's opinion, this method ensures that only that interest allocated to utility plant will be deducted. Ms. Keever noted that the staff's capital structure does not recognize the weighting-in of the unamortized balance of ITC in the overall weighted cost of capital, consistent with recent Commission practice and IRS rulings. Second, Ms. Keever calculated ITC amortization utilizing the staff recommended composite book depreciation rate of 3.16 percent. Third, Ms. Keever made several adjustments to the company's depreciation add back. Ms. Keever included 100 percent of the tax basis of test year additions (excluding Limestone 1) and retirements. Ms. Keever noted that the company agreed that its use of the 50 percent tax basis was inappropriate. Ms. Keever further adjusted the company's tax basis for Limestone 1. Ms. Keever multiplied the tax basis of plant by the composite book depreciation rate of 3.16 percent, and compared this straight line depreciation of the tax basis plant to the staff's recommended depreciation. Such calculation resulted in Ms. Keever increasing the company's return by $5,671,000 prior to calculating the FIT expense. Ms. Keever testified that while the company deducted $383,000 regarding an IRS audit and interest paid on life insurance for the company's officers, Ms. Keever chose not to deduct these items because the audit is non-recurring and the life insurance is a below the line item with the corollary interest not deductible for FIT. Ms. Keever recommended an FIT amount of $275,953,000 which is a $64,403,000 deduction in the company's request.

5. Examiners' Discussion and Recommendation.

The examiners would note that the staff's methodology for determining FIT has been followed in the past. The examiners find it the most thorough and reasonable and would recommend its adoption, together with those adjustments recommended by the examiners which should be incorporated into the staff's calculation of FIT. These adjustments include, but are not limited to, the examiners' recommended return, depreciation, capital structure, and rate base. As to OPC's request that a lower ITC percentage be adopted, the examiners would note that the company did not object to the proposal. Because HL&P apparently has an option, and the use of the 8 percent ITC would reduce the company's revenue requirement, the examiners find it reasonable on a prospective basis. As noted by Ms. Paton, this adjustment would need to be calculated by the company with flow through effects in its accumulated investment tax credits, ITC amortization and accumulated deferred taxes. Owing to the statutory time constraints in obtaining a final decision in this case, the examiners do not recommend a recalculation of the ITC amount in this case. The examiners would request that the parties with such capabilities conduct the calculation to compute the company's FIT expense as recommended herein and other revenue requirement related expenses and file such calculations with their exceptions.

I. Return

Application of a rate of return of 11.26 percent to a total invested capital of $4,687,398,911 produces a return of $527,801,117.

IX. Revenue Adjustments

A. Weather Adjustment

1. Company's Position

Company witness Purdue proposed to decrease the company's test year MWH by 141,260 MWH based upon a weather adjustment composed of adjustments to the following classes:

Residential	(80,625)
Miscellaneous General Service	(46,110)
Large General Service	(14,525)

(Schedule O-1 at 1, Rate Filing Package.)

2. City's Position

City witness Lawton found the company's econometric model to be invalid because the company considered weather as the sole explanatory variable. Mr. Lawton explained that because HL&P did not consider other variables which influence electricity consumption, such as price and appliance saturation, HL&P's model is not theoretically sound.

First, with regard to the other explanatory variables such as appliance saturation and price elasticity, Mr. Lawton determined that HL&P's failure to include such variables has led to misspecification of the model. Such misspecification leads to an incorrect weather adjustment. Moreover, in one instance, with regard to the residential model, the company employed 143 independent variables which were related to weather. Mr. Lawton found that the misspecification further invalidated HL&P's model.

Second, Mr. Lawton determined that the company's model reflected a negative relationship between consumption and weather. For example, Mr. Lawton noted that for the LGS class, in January at 10:00 a.m., if the weather became abnormally colder, these customers use less electricity until 5:59 p.m., and from 6:00 p.m. until midnight the relationship becomes positive. (City Exhibit No. 6 at 11.) In Mr. Lawton's opinion, such a phenomenon reflects the internal inconsistency of HL&P's model.

Third, Mr. Lawton noted that the company attempted to correct for autocorrelation. Autocorrelation occurs as a result of a misspecified model that cannot be corrected without a new model specification. Because the misspecification was not corrected, statistics produced by the model would be biased upward.

Fourth, Mr. Lawton also found that HL&P's model was subject to multicollinearity. Multicollinearity occurs when the independent variables are related, which cause an inability to properly interpret the estimated coefficients. Mr. Lawton concluded that multicollinearity explains why the model's statistics reflect that many of the variables in the equation are poor, but that the equation itself is statistically sound.

Fifth, Mr. Lawton testified that he would expect a t-statistic with an absolute value of 2.0 or greater. Such would indicate that the independent variable is reliable within a 95 percent confidence interval. Mr. Lawton indicated a review of the company's model reflects that the independent variables fail this simple t-test.

Mr. Lawton concluded that no weather adjustment should be applied to the company's test year sales.

3. Staff's Position

Staff economic analyst Oswald explained that the purpose of a weather adjustment is to reflect the effect that abnormal weather has on test year kWh sales. A weather adjustment which produces sales that would have occurred under normal weather conditions provides rate and earnings stability. Ms. Oswald testified that a weather adjustment should not be made if any of the following exists:

1. instability in rates is acceptable <u>and</u> the company does not typically adjust for weather;
2. test-year weather is not, in fact, abnormal; or
3. the relationship between weather and electricity demand cannot be estimated.

Ms. Oswald determined that none of the above are applicable to HL&P. Ms. Oswald further found that in only three cooling months and no heating months did the actual heating and cooling degree days fall within a normal interval. Ms. Oswald, therefore, determined a weather adjustment was necessary.

Ms. Oswald testified that while she found HL&P's model to be generally appropriate, she believed the model could be improved in two ways. First, HL&P's choice of the degree hour base may not adequately represent electric use sensitivity to weather. Ms. Oswald testified that the company's model delineates a linear relationship between per customer MWH in a given hour and a four-hour moving average of heating or cooling degree hours. The estimated relationship is compared to normal weather to calculate the level of sales which would theoretically have occurred under normal weather conditions. Ms. Oswald explained that due to the hourly data, if the hourly degree base is inappropriately chosen, the use of that heating or cooling degree hour can constitute misspecification of the model. (Mr. Purdue indicated he utilized 55^{o} and 65^{o} as his basis for heating degree hours and cooling degree hours) (Company Exhibit No. 10 at 5).) Misspecification can cause autocorrelation to exist. While the company apparently corrected for autocorrelation which may have resulted from a misspecification, Ms. Oswald stated that such was inappropriate because autocorrelation is to be expected when using hourly data. Ms. Oswald explained that an individual's usage is not expected to change on an hourly basis and thus there could exist some correlation. (Tr. at 3212.) Ms. Oswald, therefore, recommended that HL&P investigate the range of bases available for heating and cooling degree hours and test various alternatives to ensure that the impact of weather is accurately measured.

Second, Ms. Oswald found the company's decision to define normal weather as the closest bound of the confidence interval rather than the mean to be in error. Ms. Oswald explained that the confidence interval allows a statistical test for abnormal weather. Ms. Oswald further explained that by adjusting to the mean, an adjustment is made to an unbiased estimate of normal weather. However, by adjusting to the nearest confidence interval, HL&P is utilizing a biased estimate of normal weather. Such an adjustment, in Ms. Oswald's opinion, would not result in stability of rates and earnings. Ms. Oswald, therefore, recommended adoption of the company's method except that adjustments for abnormal weather should be made to the mean rather than the nearest confidence interval. With this adjustment, the total weather adjustment recommended by Ms. Oswald is 123,620 MWH which is a decrease of 17,640 MWH from the company's request.

Using her same method as discussed above, Ms. Oswald further recommended a total company coincident peak of 10,337 MWs and non-coincident peak of 11,397 MWs. Ms. Oswald noted the company had recommended 10,333 MWs and 11,394 MWs for the above coincident and non-coincident peak figures.

4. Examiners' Discussion and Recommendation

The examiners recommend adoption of the staff's weather adjustment. Although Mr. Lawton pointed to problems in the company's model, the examiners have been persuaded that they do not fatally affect the company's model. First, as to HL&P's failure to utilize other variables in its model, the examiners find such inclusion unnecessary. As Ms. Oswald explained, in using hourly temperature and usage data, there is virtually no variation in electric prices, income, or other variables because the price and income variables would not shift on an hourly basis (Staff Exhibit No. 10 at 11, Tr. at 3199.) Ms. Oswald further testified on cross-examination that even if such data were available, they would produce a negligible variation in the model. (Tr. at 3199-3200.)

Second, as to Mr. Lawton's finding of multicollinearity, Ms. Oswald testified that such a phenomenon would occur when attempting to measure two variables. (Tr. at 3202.) However, Ms. Oswald further testified that based upon HL&P's model, she would not expect to find multicollinearity, but if it did exist, it would not be harmful. (Tr. at 3202-3203.)

Third, as to the low or negative t-statistics, Ms. Oswald explained such coefficients indicate there was insufficient variation in the data to show an effect on electricity use one way or the other; these would have only a small effect on the weather adjustment. (Tr. at 3204-3208.) Ms. Oswald further indicated that the low or negative coefficients would not, in her opinion, invalidate the model. The examiners, therefore, recommend adoption of Ms. Oswald's adjustments to the company's MWH sales and MW demand figures. The examiners would note that, in brief, the company accepted Ms. Oswald's adjustments. The examiners further recommend adoption of Ms. Oswald's proposal that for future rate cases, HL&P investigate the range of bases available for heating and cooling degree hours and test alternatives to ensure that the company correctly measures the influence of weather.

B. Customer Adjustment

1. Company's Position

Mr. Purdue proposed to increase the company's test year MWH by 115,276 MWH based upon a customer adjustment composed of adjustments to the following classes:

Residential	3,321
Miscellaneous General Service	28,400
Large General Service	81,148
Public Utility	2,519
Guard Light Service	(112)

2. Staff's Position

Ms. Oswald noted that the purpose of the customer test year KWH sales adjustment is to depict that level of sales as if the test year end number of customers had been on the system throughout the test year. Ms. Oswald made the adjustment to the weather-adjusted consumption. From her analysis, Ms. Oswald recommended an increase of 126,599 MWH to the company's test year MWH based upon her customer adjustment. Ms. Oswald noted that her figure differs from the company's figure by 11,323 MWH, which may be due in part to the difference in the weather-adjusted sales.

3. Examiners' Discussion and Recommendation

The examiners would note that the city did not object to the company's customer adjustment. The company accepted the staff's adjustment. Because the examiners have recommended adoption of the staff's weather adjustment, and the staff's customer adjustment is based on its weather adjustment, the examiners recommend adoption of Ms. Oswald's customer adjustment.

C. Miscellaneous Adjustments

The company proposed the following miscellaneous adjustments for the following classes:

Miscellaneous General Service	(9,679)
Large General Service	70,393
Large Overhead Service - A	(1,534,198)
Large Overhead Service - B	(254,311)
Interruptible Service	(1,619,124)
Public Utility	(609,040)
	(3,955,959)

Mr. Purdue testified that adjustments were made to the MGS, LGS, LOS-A, LOS-B, and Interruptible Transmission customers for initiation of new service, suspension of service, customer transfer from one rate class to another, contract changes, or tariff modifications. In particular, Mr. Purdue noted that Texas-New Mexico Power Company's (TNP) sales have decreased significantly since March 1985 when TNP began purchasing power from Capitol Cogeneration.

No party objected to the company's proposed adjustments. The examiners find them to be reasonable and urge the adoption of the company's proposed miscellaneous adjustments.

D. Other Revenues

1. Staff's Position

Staff accountant Young recommended that the company's other revenue be reduced by $11,163,000. First, Mr. Young testified that staff rate analyst George Mentrup recommended reduction of HL&P's miscellaneous revenues by $146,000. Second, Mr. Young recommended that because HL&P proposed that local gross receipts tax be surcharged on customer utility bills, it is necessary to adjust other revenues to offset the local gross receipt tax expense recognized in the cost of service so that the local gross receipts would not be included in the company's base rate revenues. The remaining difference of $11,017,000 results from the staff's local gross receipt tax expense recommendation.

2. Examiners' Discussion and Recommendation

The examiners recommend denial of the $146,000 adjustment. Although the examiners were referenced to Mr. Mentrup's testimony for an explanation of this adjustment, the examiners did not find that Mr. Mentrup discussed this issue. The examiners recommend adoption of the remainder of Mr. Young's adjustment because it accurately excludes the local gross receipts tax revenues from the company's base rate revenues.

E. Off-System Sales

1. OPC's Position

In brief, OPC recommended a revenue increase of $12,229,000 owing to off-system sales. (OPC Brief at 104-5.) This figure reflects a 12-month figure ending May 1986. OPC stated that during the test year, the company received $7,716,000 in off-system revenues. The company excluded these revenues in its calculation of its revenue deficiency. Although OPC characterizes the adjustment as an interchange adjustment; as Mr. Brian, who provided OPC with the $12.2 million figure, stated on cross-examination, interchange sales were those exchanges done in kind where no transfer of funds occur. The figures OPC requested related to off-system sales and purchases of the company. (Tr. at 832.) Nevertheless, company witness Purdue referred to such sales as interchange sales. (Tr. at 4761.) Thus, there appears to be some confusion as to their proper name, but not their purpose. In brief, OPC points out that during the first five months of 1986, the company's off-system sales totaled almost $7 million. (Tr. at 831, OPC Brief at 104.) OPC argues that although the company zeroed out the revenues associated with these sales owing to their unpredictability, the above figures reflect that the revenues are known and measurable.

2. Company's Position

Company witness Purdue testified that the company excluded all amounts relating to off-system sales because such sales are not known and measurable, not necessarily recurring and highly unpredictable. (Tr. at 476.) Company witness Brian, who also testified to the volatility of such sales, further indicated that the company excluded any off-system purchases from its cost of service. (Tr. at 970.)

3. Examiners' Discussion and Recommendation

While OPC argued that sales have occurred in 1985 and 1986, Mr. Brian testified that the company had zero revenues arising from off-system sales in 1984. (Tr. at 832.) The company was consistent in its treatment by excluding both off-system sales and purchases. The examiners, therefore, agree with the company that such sales are not known and measurable and recommend against such an adjustment.

F. Wheeling Revenues

City witness McKinney increased the company's wheeling revenues by $1,241,000 resulting in wheeling revenues of $4,797,000 for the rate year. Ms. McKinney stated that she included additional wheeling revenues which arose from a new contract with Texas Gulf Cogeneration and an additional contract with Dow Chemical.

The examiners note that the company does not oppose the city's adjustment. More importantly, the examiners find such increase reasonable because it is known and measurable. The examiners recommend adoption of the city's proposal to increase wheeling revenues by $1,241,000.

G. Fuel Revenues

The company's fuel revenues are composed of reconcilable and nonreconcilable costs. Nonreconcilable fuel expenses have been included in cost of service and will be recovered via base rate revenues. Reconcilable fuel expenses of $1,005,782,707 will be recovered through the fixed fuel factor, and fuel factor revenues should be set equal to that amount. The company's proposed fuel factor revenue adjustment has been rejected in Section VIII.B.7, above.

XI. Cost of Service Study/Cost Allocation Methodology

A. Introduction

The primary purpose of a cost of service study is to allocate to each rate class an appropriate amount of the utility's expense incurred in providing service to its members so that equitable rates can be formulated, helping to insure that the assignment of cost reflects, as nearly as possible, the true nature of cost causation. The goal is to establish a basis for formulating rates which enables the utility to recover its authorized revenue requirement, but at the same time does not unduly burden any one customer class to the benefit of another (or others).

[25] The methodology generally followed in most cost of service studies utilizes three steps: functionalization, classification and allocation. The first step, functionalization, involves the grouping of plant and expenses into homogeneous groups or accounts. This is normally done through the Uniform System of Accounts. Generally the functional plant accounts include: intangible, production, transmission, distribution, and general plant. The operation and maintenance (O&M) functional expense accounts generally include: power production, transmission, distribution, customer accounts, sales, and administrative and general expenses.

The next step involves the classification of the homogeneous accounts into demand, energy or customer related cost components, based on the perceived cause for the expenditure of funds for the particular type of plant or expense. Demand (load or capacity) related costs are those costs associated with the fixed plant investment and expenses required to meet the maximum kilowatt (KW) demand placed on the system by the various customers. The amount of system demand determines the size of a utility's production, transmission and distribution facilities which must be capable of meeting customer needs at the time and levels required.

Energy (variable) related costs are those which vary with the kilowatt hours (KWH) consumed. An example of an energy related cost is fuel expense.

Customer related costs are those costs incurred by the utility as the result of a customer's existence on the system, regardless of the demand imposed and energy consumed, or when such occurs. Examples of customer related costs include: bill preparation, service drops, and meter readings.

The final step (generally the most contested aspect of the rate design phase of electric rate cases) involves the allocation of the classified amounts to the various classes of service by factors related to demand, energy use, and number of customers. A number of methodologies exist for allocating costs. Those proposed in this case are: probability of a negative margin (PONM OR Probability Peak), 4 coincident peak (4-CP), 4 coincident peak average and excess (4-CP A&E), near peak, and capital substitution (CAPSUB). Although the allocation methodology proposals differ, the parties generally agree that, to the extent possible, costs should be assigned on the basis of each class' proportionate responsibility for the incurrence of such costs. However, the parties disagree as to the appropriate methodology through which to achieve this objective. Regardless of the methodology ultimately deemed appropriate and utilized, HL&P pointed out that such should:

1. Track cost
2. Recognize off-peak usage
3. Recognize demand diversity
4. Provide stable results over time
5. Allocate cost to time periods

(HL&P Ex. 10 at 24.)

No one allocation methodology is considered appropriate in <u>all</u> cases; although it is the position of some that methodologies such as CAPSUB are almost always inappropriate. What is deemed an "appropriate" methodology may vary not only from one utility to another, but also from one of a utility's rate cases to another. This is evidenced by the fact that most of the witnesses testifying in this case have, at one time or another, proposed allocation methodologies different from that being sponsored in this case. The allocation methodologies proposed herein are each discussed below. It is noted that except to the extent modified in Sections XI. B.-H. of this report, the examiners have accepted HL&P's cost of service study and recommend its approval.

B. Production Capacity Cost Allocation

1. Production Plant

a. PONM. HL&P proposed the utilization of the PONM methodology for allocating production costs in this case. All of HL&P's investment in production plant was assigned to the production function, and subsequently to the capacity-related cost classification. HL&P witness James N. Purdue testified that the PONM methodology: has been approved by the Commission in the past; tracks cost from a generation planning point of view; recognizes off-peak use and demand diversity; has provided stable results from year to year; and recognizes seasonal and diurnal variations in cost responsibility. (HL&P Ex. 10 at 24-25.)

According to Mr. Purdue the PONM methodology considers usage patterns for all hours of the year, but in determining the amount of capacity needed, weight is given only to those hours in which the probability exists of the utility being unable to meet the system load. Mr. Purdue testified that the PONM accounts for interaction among generating unit size, forced outage rate, scheduled maintenance, system load and the particular class load patterns. He noted that no weight is given the load in many hours of the year since the PONM is zero when carried to five decimal places. (Id., at 25-26.) For the test year, 1,474 out of 8,760 hours had a PONM greater than zero; but only 297 hours (3.39 percent) accounted for 90 percent of the relative weighting. (Id., at 27-28 and Tr. at 3819-3820.)

Explaining the specific derivation of the allocation factors, Mr. Purdue testified that the PONM for each hour of the year was first calculated using a computer model which determines the probability of a positive margin (POPM) for various assumed outages. The basic input for the computer model includes: the generating units by capability in MW, the associated forced outage rates and scheduled maintenance dates, and seasonal changes in capability. The basic output is the POPM for each assumed outage condition for each scheduled maintenance period. The PONM for each hour is calculated by subtracting POPM from one (1). Utilizing a "table look-up technique" the PONM for an outage level is selected that corresponds to the available margin between capacity and load in a particular hour. PONM equals the probability of being unable to supply the particular margin between capacity in service and load. Finally, a single weighted capacity responsibility factor for each class is calculated by weighting the capacity responsibility in each hour by the respective PONM; which weighting is in proportion to the ratio of the PONM in a given hour to the sum of the PONMs for the period analyzed. (Id., at 26-27.)

Only firm loads are included in the PONM calculations. Interruptible loads are not included as such can be interrupted whenever system problems are experienced. Mr. Purdue testified that revenue related to the interruptible service is separated into fuel and non-fuel related components; with fuel related revenue and expense being allocated on the basis of each class' relative MWH sales at the generator, and non-fuel related revenues being allocated to each class based on capacity related production allocation factors. Mr. Purdue testified that interruptible service costs were allocated in this manner because the cost of providing this service cannot be determined in the manner generally applied to firm service. As the interruptible service revenue is part of HL&P's overall cost of service, the revenue and fuel expenses are allocated back to the firm rate classes in the manner set forth above. The interruptible service revenue reduces the overall revenue requirements of firm service customers. (Id., at 28.) Stand-by service was accounted for in this same manner in the cost allocation study; revenue was allocated to all classes based on production allocation factors, but load for stand-by service was not used in the development of the factors. (Id., at 29.)

HL&P's proposed allocation factors for production costs based on the PONM method are set forth below:

PONM

Rate Class	Allocation Factors
RES	0.370756
MGS	0.265888
LGS	0.169931
LOS-A	0.054856
LOS-B	0.110365
PU	0.028151
SPL	0.000048
GL	0.000005

City of Houston witness Michael J. Ileo agreed with HL&P's use of the PONM methodology to allocate production costs, but disagreed with the company's treatment of the interruptible service in its cost allocation study. In Dr. Ileo's opinion the interruptible service should be identified and treated as a separate service category. Dr. Ileo testified that by not doing so, it is not possible to directly ascertain the rate of return associated with the interruptible service. Dr. Ileo also pointed out that despite a contribution to actual system peak demands, HL&P's cost allocation study does not allocate any demand-related generation and transmission costs to the interruptible service. Dr. Ileo testified that while interruptible service is of a lesser quality than firm service, historically interruptible service customers have remained on the system, contribute to system peak demand, and have rarely been interrupted at times of peak demand. (Cities Ex. 58 at 3-4.) To illustrate this point Dr. Ileo references certain data requests answered by HL&P. Specifically referenced were: RFI (request for information) No. HOU 10-12 which shows the interruptible service loads and consumption for the past five years; and RFI Nos. HOU 12-1 and TIEC 1-6 which indicate no interruptions in 1984 and 1986 to date, two interruptions in 1985 (five customers on April 16 and six customers on May 16), two interruptions in 1983 (five customers on each December 22 and 25), six interruptions in 1982 (one customer on January 11, 12, 13, 14, 15 and three customers on May 25), and one interruption in 1981 (one customer on January 18). From this data Dr. Ileo concluded that there have been no interruptions of interruptible service customers during the peak summer months over the past five years; and that the frequency of the interruptions appear to be lessening in the winter months. (Id., at 15-16.) Dr. Ileo also observed that HL&P did not base its cost allocation and revenue distribution on actual test year sales and loads for the interruptible service. (Id., at 4.) For these reasons Dr. Ileo performed his own cost allocation study treating the interruptible service as a separate and identifiable service category, using actual test year MWH sales and MW loads for interruptible cost allocation purposes. As the examiners read Dr. Ileo's schedules accompanying his direct testimony, the City of Houston (and

Coalition of Cities) proposes, the following allocation factors for HL&P's production costs in this case:

Rate Class	Cities PONM Allocation Factors
RES	0.348239
MGS	0.258656
LGS	0.162687
LOS-A	0.052502
LOS-B	0.101486
IS	0.050405
PU	0.026022
SPL	0
GL	0

DOE witness Dennis W. Goins supported HL&P's proposed cost allocation for production costs as submitted. Mr. Goins first observed that HL&P correctly classified all production plant costs as demand-related costs, testifying that the following factors support such classification: (1) production plant costs represent costs incurred by HL&P to install generating plant and equipment to meet load; and (2) annual plant costs are relatively fixed over the accounting life of the plant and equipment and do not vary with plant output, i.e., KWH production. (DOE Ex. 1 at 5-6.)

Mr. Goins further testified that the PONM methodology used by HL&P is a reasonable and acceptable method of allocating demand-related production costs; noting that the methodology attempts to assign responsibility for demand-related production costs according to each class' contribution to the need for and relative use of the utility's aggregate generating capacity. (Id., at 4 and 9.)

Mr. Goins also testified that changes in a utility's capacity reserve situation do influence the production cost allocation factor developed for each class. He noted that holding constant total system capacity, a uniform percentage increase in aggregate reserve margins across all hours will increase relative PONM values for peak hours compared to relative PONM values for off-peak hours; the opposite effect on relative PONM values and allocation factors occurs with a uniform percentage decrease in reserve margins across all hours. Likewise, a uniform percentage increase in loads across all hours increases the cost responsibility of peak-period users relative to the cost responsibility assigned to off-peak users; the opposite effect occurs with a uniform percentage decrease in loads across all hours. According to Mr. Goins the PONM method, by linking demands to the capacity situation facing a utility, attempts to ensure that classes responsible for the capacity situation bear a fair share of any capacity excess or shortage. (Id., at 9-10.)

If loads are held constant and a new generating facility is added, a decrease in relative PONM values in peak compared to off-peak hours should occur, resulting in a decrease in the peak period allocation factors and an increase in off-peak allocation factors. Precise changes depend on factors such as: the size of the generating unit, how it is operated, its forced outage rate, and its maintenance schedule. (Id., at 10.)

U.S. Steel/USX witness Michael K. Moore ultimately accepted the PONM methodology as a reasonable method of allocating production costs in this case; although he initially testified that in his opinion the 4-CP methodology is the most appropriate method for allocating HL&P's demand-related production costs for the following reasons. First, production plant should be allocated in a manner consistent with the criteria used by the utility in its capacity expansion planning process. Therefore, PONM is appropriate for a utility which utilizes a loss of load probability (LOLP) or loss of load expectation (LOLE) criterion as the primary determinant of system capacity requirements. However, HL&P acknowledged in an RFI response that the company does not utilize the LOLP or LOLE method. Rather, HL&P primarily determines capacity requirements based on a percentage of peak demand reserve margin. (U.S. Steel/USX Ex. 1 at 10-11.)

Second, under the percentage reserve margin criterion capacity requirements are calculated as the system annual firm peak demand plus a specified percentage reserve margin. According to Mr. Moore, since the annual peak demand is the most significant factor in HL&P's capacity planning process, the appropriate allocation for production costs should be based upon class contributions to peak demand; in this case a 4-CP allocation. (Id., at 11-12.)

Notwithstanding the foregoing conclusions, Mr. Moore testified that he has no objection to utilizing the PONM method proposed by HL&P since the allocation factors resulting from the PONM method are not substantially different from the 4-CP allocation factors. (Id., at 12.) A comparison of the PONM and 4-CP allocation factors is set forth below:

Rate Class	PONM Allocation Factors	4-CP Allocation Factors	Absolute Difference	Relative Difference (%)
RES	.370756	.369001	(.001755)	(.47)
MGS	.265888	.272446	.006558	2.47
LGS	.169931	.170452	.000521	.31
LOS-A	.054856	.054862	.000006	.01
LOS-B	.110365	.106048	(.004317)	(3.91)
PU	.028151	.027192	(.000959)	(3.41)
SPL	.000048	.000000	(.000048)	(100.00)
GL	.000005	.000000	(.000005)	(100.00)
TOTAL	1.000000	1.000001		

(U.S. Steel/USX Ex. 1, Sch. C-1.0. Source of data: Page 10 of Sch. P-1.A of HL&P's rate filing package.)

Staff witness Jeffrey D. Rudolph also supported HL&P's PONM methodology proposed herein. Mr. Rudolph testified that a production-capacity allocator should: (1) be reflective of cost causality principles; and (2) yield a revenue contribution from each and every class since production plant is typically characterized as common facilities jointly used by all customers. (Staff Ex. 28 at 4-5.) Mr. Rudolph testified that PONM is a "viable alternative" for allocating production-capacity costs because it recognizes these two features and is therefore "robust enough" to be applied in this case. (Id., at 6-7.)

Four parties to this proceeding--TNP, Champion, TIEC, and OPC--opposed the utilization of the PONM methodology for purposes of allocating HL&P's production costs; each proposing a different alternative for said allocation. The various alternative proposals will be discussed later in this report.

TNP witness Albert H. Schuman identified the following as problems he perceived with utilizing the PONM methodology to allocate production capacity costs:

1. The inflexibility of the planned maintenance. The computer mode cannot shift scheduled maintenance to different time periods as management would in actual operating conditions, therefore a negative margin could be reflected in instances where none would in fact occur.

2. The use of historical unit forced outage rates assumes static conditions when in fact forced outages occur randomly and unpredictably.

3. The data input is subject to manipulation such that negative margins could be produced at will.

4. PONM is an extremely complex methodology which:

   a. Requires the use of a computer;
   b. Is not readily understandable by most people;
   c. Requires load data for 8,760 hours in order to function; and
   d. Requires sophisticated computer programs to make numerous (a minimum of 8,760) calculations to produce the ultimate allocation factors for each customer class.

5. PONM bases the allocation of production costs on a generation planning point of view rather than on actual cost causation by the various customer classes.

(TNP Ex. 6 at 5-11.) For these reasons Mr. Schuman recommended that the PONM methodology be rejected.

Champion witness Kenneth Eisdorfer offered the following criticisms of the PONM methodology proposed by HL&P. First, Mr. Eisdorfer testified, HL&P's

calculations of PONM's cannot be reflective of the company's true system reliability because:

1. System dynamics are ignored. The methodology assumes a static system when, in most instances, the utility will be able to effect remedial action regarding a developing negative margin.

2. The PONM methodology fails to consider all of the generation resources available to HL&P such as: HL&P's interconnection with the Electricity Resource Council of Texas (ERCOT), and HL&P's occasional imposed system voltage reductions used to increase the company's load carrying capability.

3. PONM considers unit outages in a fallacious manner by treating forced outages as if they occur uniformly throughout the year, and assuming that scheduled maintenance cannot be postponed.

4. The specific unit outage data utilized as inputs for PONM calculations are deficient to the extent that: (a) scheduled maintenance data for 1986 was used in the study, but there were wide variances between planned scheduled maintenance hours and actual scheduled maintenance hours for three of the four months of January through April; and (b) the forced outage rates used in the study bear no resemblance to those actually experienced during the test year.

(Champion Ex. 1 at 18-23.)

Mr. Eisdorfer further testified that the PONM methodology has not produced stable results over the years as the number of hours with significant probabilities of negative margins has fluctuated wildly from one rate case to another. In Mr. Eisdorfer's opinion the PONM methodology is inherently unstable because the results produced are extremely sensitive to the quality of the various inputs. (Id., at 23-25.)

Finally, Mr. Eisdorfer testified that the PONM methodology is fundamentally flawed because it improperly attributes responsibility for the magnitude of HL&P's fixed costs to system loads below the annual system peak when in fact it is the magnitude of the annual system peak which dictates the amount of generation capacity needed. (Id., at 25.)

Mr. Eisdorfer concluded that the PONM methodology should be rejected because it cannot produce results that are reflective of class cost-causation. (Id., at 26.)

Champion witness Brian Kalcic also testified PONM fails to properly recognize the reasons fixed costs--which are either demand or customer related--are incurred by a utility. Demand-related costs are incurred due to the utility's obligation to provide service when requested and the annual peak load determines the level of capacity needed to meet this obligation. Accordingly, Mr. Kalcic testified, these costs should be allocated to classes on the basis of each class' contribution to the system peak; such is not reflected by the PONM method. Instead, the PONM method--depending on the inputs--assigns varying degrees of weight to off-peak hours; thereby improperly penalizing those classes which utilize HL&P's capacity in off-peak periods when the utility should be discouraging usage during peak periods. (Champion Ex. 2 at 9-11.)

TIEC witness Dale Thomas also opposed the utilization of the PONM methodology in this case for the following reasons. First, while the PONM's utilization of a greater number of demand measurements might appear to produce more stable results, this is not necessarily the case. Specifically, because the PONM methodology is a function of both system load and system supply the results produced can be affected by the system's operating characteristics (e.g., scheduled maintenance, forced outage rates, and capacity ratings). Mr. Thomas testified that when the amount of unavailable capacity is substantial, due to scheduled maintenance or forced outages, the reserve margin can become smaller; and as the reserve margin decreases, the PONMs increase. It is therefore possible to assign a higher probability of negative margin to non-summer as opposed to summer months by scheduling maintenance during this period. Mr. Thomas pointed out however that as the reason for scheduling maintenance during non-summer months is to ensure the availability of capacity to meet summer demands, the non-summer PONMs and corresponding production capacity costs should be attributed to the summer peak demands. (TIEC Ex. 7 at 13-14.)

Mr. Thomas further testified that the calculation of PONMs on an hourly basis treats each hour independently in determining the need for additional generating capacity; erroneously assuming that the utility can start up and shut down the available generating units each hour irrespective of requirements in previous or subsequent hours. (Id., at 14-15.)

Finally, Mr. Thomas noted that if the PONM methodology is to be utilized it should be modified to exclude from the analysis scheduled maintenance influences. Additionally, Mr. Thomas pointed out that forced outage rates, planned maintenance schedules and the level of firm cogeneration capacity included in the resource stack all influence the PONM factors, but do not directly relate to capacity cost-causation; therefore the utilization of these parameters to develop production capacity cost allocation factors is inappropriate. (Id., at 15.)

For these reasons TIEC urged the rejection of the PONM methodology in this case.

OPC witness Steven Andersen testified that the allocation of all production capacity charges on the basis of each class' proportionate contribution to load during hours in which the PONM is significantly greater than zero is not reasonable. Dr. Andersen testified that PONM is a variant of the traditional coincident peak methodology and its potential superiority lies in the fact that it considers all hours of the year during which demand encroaches on available capacity. By doing so, PONM represents a more objective and systematic measure of class responsibility for the cost of reliability. (OPC Ex. 89 at 8.)

However, Dr. Andersen testified, PONM is deficient as a generalized capacity cost allocator because it fails to provide the type of data required to make a choice between oil, gas, coal or nuclear technologies; which choice ultimately depends on whether higher capacity costs are justified by lower operating costs. In Dr. Andersen's opinion PONM fails to explain both the amount and mix of capacity required to meet system demands. (Id., at 8-9.) Dr. Andersen also cited testimony on behalf of HL&P in prior cases to illustrate his point that PONM fails to adequately reflect the full range of factors considered by HL&P in planning for capacity expansion. (Id., at 9-12.)

Dr. Andersen further testified that the principle of peak responsibility was not entirely inappropriate for allocating total capacity costs when natural gas was inexpensive and the range of technological choices considered by Texas utilities was relatively narrow. However, as gas prices escalated and its availability grew uncertain; as coal and nuclear capacity became viable alternatives to natural gas; and with the emergence of new technology (combustion turbines) as a means of quickly improving system reliability at a relatively low cost; the capacity planning process became more complex. Accordingly, Dr. Andersen noted, more sophisticated cost allocation methodologies are now required if a reasonable correspondence between cost responsibility and cost causation is to be established. (Id., at 12-13.)

Dr. Andersen also pointed out that the mere deferral or cancellation of a generating unit when projected increases in peak demand do not materialize does not mean the unit was being built for the sole purpose of meeting peak demand. Rather, such would indicate that prospective fuel cost savings alone are not sufficient to justify the original construction schedule. (Id., at 14.)

For these reasons OPC opposed the allocation of all production capacity costs on a peak responsibility basis.

On rebuttal HL&P witness Herbert J. Edwards testified that in deciding on a particular allocation technique the following factors should be considered:

1. Effectiveness in recognizing cost causation.
2. Applicability to the specific circumstances.
3. Completeness of supporting analysis.
4. Ease of presentation and understanding.

5. Consistency and reasonableness of the end results.

6. Consistency with overall pricing objectives.

(HL&P Ex. 56 at 8-10.)

Mr. Edwards testified that the PONM method has been approved by the Commission in Docket Nos. 2001, 2676 and 3955. (Id., at 11.) He further testified that the PONM method used by HL&P in this case is a sound, workable, application of peak responsibility costing and is technically superior to all other alternatives proposed herein. Mr. Edwards acknowledged that it may be desirable in the future to expand the analytical framework of PONM by considering demand variability as well as supply uncertainty. He noted that the probable effect of this would be to increase the number of hours in which a negative margin is indicated, thus limiting the tendency for the method to converge on a straight CP approach as reserve margins increase; and possibly developing overall results which reflect more of an energy recognition than now exists. (Id., at 29.)

Also on rebuttal Mr. Purdue testified that no matter how theoretically sound a methodology might be, if the results are not reasonable, then they are not useful. To test the reasonableness of the results of various proposals, Mr. Purdue prepared Chart TNP-8 entitled Spectrum of Production Allocation Factors, which included the results of a 4-NCP A&E analysis, a method not directly proposed by any party herein. Mr. Purdue concluded that the PONM method yields results which are reasonable for allocating production demand costs in this case, testifying that:

> It is my belief that extreme positions at either end of the spectrum of expected results, i.e. energy or coincident peak, are potentially harmful. I also believe that A&E 4-NCP method can typically be expected to yield results which moderate the extremes by its explicit inclusion of both energy and demand in the algebra. It is the benchmark upon which I have measured other allocation results.

(HL&P Ex. 55 at 9.) Mr. Purdue further testified that while he used the A&E 4-NCP method as a benchmark, the PONM method is preferable because: (1) it has proven to be a superior allocation method at HL&P over the years; and (2) while it does not explicitly consider energy, it does consider system demand for every hour of the year and each class' contribution thereto, while comparing this to the available production supply. (Id., at 8-9.)

b. 4-CP. Champion witness Kalcic testified in support of the use of the 4-CP method in this case. Mr. Kalcic testified that HL&P's summer peak loads are consistently higher than its non-summer load, with the coincident peaks occurring during the months of June through September. Mr. Kalcic further testified that HL&P's annual system peak has always occurred during the months of either July or August, with the June and September peaks averaging 96 percent of the annual peak. In contrast, he noted, no non-summer month has averaged as much as 90 percent of the annual system peak, with all but two months (May and October) averaging less than 80 percent. According to Mr. Kalcic the predominance of summertime system peaks indicates that HL&P sizes its generation facilities to meet demands during this period. Mr. Kalcic therefore recommended that the 4-CP method be used to allocate HL&P's production capacity costs. (Id., at 11-12.) Mr. Kalcic's recommendation results in the following allocation factors in this case:

4-CP Methodology

Rate Class	Allocation Factors
RES	0.369000
MGS	0.272446
LGS	0.170452
LOS-A	0.054862
LOS-B	0.106048
PU	0.027192
SPL	0.000000
GL	0.000000

As previously noted, U.S. Steel/USX witness Moore testified that in his opinion the 4-CP method is the more appropriate allocation methodology for allocating production capacity costs, but given the similarity of results in this case between the PONM and 4-CP methods, he accepted the former. (See discussion in Section XI.B. 1. of this report.)

HL&P witness Edwards testified that the 4-CP method proposed by Mr. Kalcic has two drawbacks; (1) it is too straight forward, because it is too simplistic as a barometer of cost causation if better measures are available; and (2) it allows for a "free ride" to occur (due to the allocation of no production capacity costs to certain classes) which suggests irrationality in terms of cost causation and simple fairness. (HL&P Ex. 56 at 14.)

c. 4-CP Average & Excess (A&E). TNP witness Schuman proposed the allocation of HL&P's production capacity costs on the basis of the 4-CP A&E method; which, he testified, was adopted by the Commission in Docket No. 4540, Application of Houston Lighting and Power Company for Authority to Change Rates, 8 P.U.C. BULL. 75 (December 6, 1982). (TNP Ex. 6 at 11.) Mr. Schuman testified that the benefits of the 4-CP A&E method are as follows:

1. It recognizes the diversity among class loads; which provides a benefit to those classes whose load patterns provide greater diversity to the operating system, thereby reducing the need for additional capacity.

2. It considers the various class' energy consumption as well as peak demand requirements; thereby allocating some portion of investment and expense on the basis of energy and some on demand. It also allocates some of the costs to off-peak users.

3. It is readily understandable, requiring a minimum of data in order to be calculated.

4. It satisfies the criteria set forth by HL&P witness Purdue in choosing an appropriate allocation methodology; specifically it: tracks costs, recognizes off-peak usage, recognizes demand diversity, provides stable results over time, and allocates cost to time periods.

5. It utilizes two types of measurements in the allocation of demand-related costs, making a distinction between the cost of facilities to serve the average load and the cost of facilities to serve the excess load. The demand costs equal to the

system load factor are allocated on the average demand basis, while the excess demand element is then allocated on the difference between the maximum class demands and their average demands.

6. It takes into account the importance of relative use of facilities or customer group load factors. System facilities are allocated in proportion to relative use. The opportunity for diversity is recognized as a linear relation which decreases with increasing load factor. The effect is to allocate proportionately less of the diversity benefits to the high-load factor customers and more benefits to the low-load factor customers.

(Id., at 12-14.)

The allocation factors resulting from Mr. Schuman's 4-CP A&E calculations are as follows:

Rate Class	Schuman 4-CP A&E Allocation Factors
RES	0.324403
MGS	0.257528
LGS	0.178266
LOS-A	0.069896
LOS-B	0.144023
PU	0.022460
SPL	0.003122
GL	0.000302

On rebuttal HL&P witness Purdue testified that while Mr. Schuman indicates that the methodology he utilized herein is the same as that proposed by the staff and adopted by the Commission in Docket No. 4540, it is not the same; and while Mr. Schuman cites the NARUC cost allocation manual as support for his methodology, again the method is not the same. Mr. Purdue further testified that there appears to be an error in Mr. Schuman's calculation, illustrated at his Exhibit AHS-2. Specifically, he used NCP (non-coincident peak) demands for the Street and Protective Lighting and Guard Lights classes, where his formulae indicate average demands should be used. Mr. Schuman also used 31MW and 3MW respectively in his calculations for these two classes when 16MW and 2MW respectively should have been used. Finally, Mr. Purdue testified that Mr. Schuman's 4-CP A&E calculation in this docket differs substantially from the 4-NCP A&E calculation he proposed in Docket No. 5779. (HL&P Ex. 55 at 5.)

HL&P witness Edwards testified that the traditional 4-CP A&E method lacks a cost-causal basis, in that it does not "exactly" reflect cost causation but is only an approximation thereof. According to Mr. Edwards this is true because of the introduction of average demand without a double-counting problem (the use of "excess" demands for each class eliminate that) and because the excess demands, being based on class NCP, tend to track coincident peak demands for most classes. (HL&P Ex. 56 at 28.)

Regarding the 4-CP A&E method in which class excess demands are based on CP demands (the method utilized by the staff to allocate transmission costs) Mr. Edwards testified that:

> This is actually an unreconstructed CP demand allocation method with the single virtue that "free ride" problems are eliminated in the case of lighting classes. I do not believe that it is accurate to characterize that method as reflective of "energy responsibility" goals.

(Id.)

Finally Mr. Edwards testified that if an explicit recognition of energy is desirable enough to offset the historic use of cost causation standards, then he would recommend the use of the traditional average and excess method (i.e., excess allocated on the basis of class NCP) in lieu of PONM. (Id., at 29.) He noted that this method is "well-understood usually well-behaved, and does not appear to be too radical a departure from historical results." (Id., at 30.)

The allocation factors resulting from the A&E 4-NCP method are as follows:

Rate Class	Allocation Factors A&E 4-NCP
RES	0.376369
MGS	0.262684
LGS	0.164648
LOS-A	0.053692
LOS-B	0.105806
PU	0.033641
SPL	0.002883
GL	0.000277

(HL&P Ex. 55, Chart JNP-8.)

d. Near Peak. TIEC witnesses Jeffrey Pollock and Dale Thomas testified that the "near peak" method is the most appropriate method of allocating HL&P's production costs as it is reflective of capacity cost causation for the company. (TIEC Ex. 5 at 6 and TIEC Ex. 7 at 11-12, respectively.) Mr. Thomas explained that the near peak demand method recognizes HL&P's predominant summer-peaking characteristic, as well as the fact that HL&P generally experiences its lowest reserve and capacity margins during the summer (peak) months. Therefore, he noted, the demands imposed during the time that load is nearest the annual peak determine the amount of capacity which must be installed to enable HL&P to provide nearly continuous service. (TIEC Ex. 7 at 12.)

Mr. Thomas testified that the near peak demand allocation factors were derived by summing the coincident demands of each customer class during those hours in which the total system demand (excluding interruptible load) was within 5 percent of the annual system peak. According to Mr. Thomas there were 54 such occurrences (between the hours of 2:00 p.m. and 7:00 p.m.) during the test year. Mr. Thomas testified that the near peak method considers a broader spectrum of hours than other summer CP methods; and the use of 5 percent as the threshold for determining when the system is near peak recognizes the period when system reliability is most critical as the highest PONMs occur during these hours.

(*Id.*, at 12-13.) The allocation factors resulting from the near peak method are as follows:

Near-Peak

Rate Class	Allocation Factors
RES	0.380300
MGS	0.263400
LGS	0.167700
LOS-A	0.052800
LOS-B	0.106700
PU	0.029100
SPL	0.000000
GL	0.000000

HL&P witness Edwards testified that the near peak method is a variant of peak responsibility recognizing all loads as "peak" which lie within a selected range of the annual peak load. (HL&P Ex. 56 at 12.) Mr. Edwards testified that while this method has the advantage of reflecting peak responsibility concepts, it also allows more subjective judgment to enter into the costing process at the expense of objectivity. According to Mr. Edwards the advantage PONM has over the near peak method is the partial removal of judgment from the process of arriving at a decision. (*Id.*, at 15-16.)

e. CAPSUB. OPC proposed the allocation of production capacity costs utilizing the CAPSUB method, which classifies and allocates a significant amount of capacity costs on an energy (rather than demand) basis. OPC witness Andersen testified that high load factor customers criticize CAPSUB on the following grounds:

a. Allocation of a portion of capacity costs on energy and a portion on coincident peak results in charging customers twice for the average demand component of coincident peak demand.

b. As generally applied, the capital substitution model fails to provide a consistent treatment of fuel expense and capacity cost.

c. As a result of declining natural gas prices the fuel savings that were expected to result from reduced dependence on natural gas have failed to materialize. Therefore, the model is inconsistent with reality.

d. It is inappropriate to use replacement cost in determining the share of capacity cost that is classified as energy related because different types of capacity have different useful lives.

e. The capital substitution model oversimplifies the capacity expansion planning process.

(OPC Ex. 89 at 17.) Dr. Andersen disagrees with these criticisms and prepared an evaluation of them which accompanied his direct testimony as Appendix E.

Dr. Andersen testified that the primary objectives pursued in generation planning are reliable service and minimization of costs. According to Dr. Andersen "if reliability is expressed as a reserve margin at time of system peak, then the only type of capacity required to satisfy the reliability target is a combustion turbine," and that "since combustion turbines generally represent the least expensive means of enhancing reserve margins, the cost of these units represents a ceiling on the cost of reliability." (Id., at 3.) Dr. Andersen used the 1985 replacement cost of combustion turbine capacity--$220 per KW--as a benchmark for calculating the cost of reliability. He noted that an analysis of nationwide combustion turbine capacity additions between 1972 and 1979 indicates an average 1985 replacement cost of $218 per KW; and according to the General Electric Company (G.E.), the replacement cost of combustion turbine capacity is $220 per KW in 1985 dollars. (Id., at 18.)

To determine the 1985 cost for the remainder of HL&P's gas-fired capacity Dr. Andersen testified that the replacement cost for all gas-fired steam capacity operated at a capacity factor in excess of 15 percent was estimated on the basis of combined cycle units. Dr. Andersen used an estimate of $450 per KW in his analysis based on data provided by G.E. (Id., at 19.)

Dr. Andersen estimated the replacement cost for lignite capacity on the basis of the construction cost of Limestone, $903 per KW. The total cost of lignite capacity is $1,156 per KW (including a 28 percent allowance for AFUDC), based on a seven year distribution for construction expenditures. The construction cost for coal capacity, $1,050 per KW, was based on the ten percent cost premium for lignite over coal. (Id., at 20.)

Based on his analysis Dr. Andersen determined the composite classification of total production plant to be 41.28 percent demand and 58.72 percent energy. (Id., at 20-21.)

To allocate the energy-related component of production plant Dr. Andersen distributed the replacement cost across months for each generating unit in proportion to the relative share of annual generation occurring within each month. Within each month, energy related investment was allocated to customer classes on the basis of class contribution to average demand. Thereafter the allocation factors were calculated by dividing each class' share of the energy component of production plant (the sum across 12 months) by the system total. (Id., at 21-22.)

Regarding the allocation of the reliability component of total capacity costs, Dr. Andersen testified that notwithstanding the fact that PONM represents a superior indicator of class responsibility for the cost of reliability, he utilized the 4-CP method in his analysis. The primary reason, he testified, is that HL&P uses a target reserve margin rather than a target PONM for system planning purposes; therefore, use of a 4-CP allocator maintains a greater degree of consistency between the proposed allocation of cost and HL&P planning criteria. (Id., at 22.)

However, not all reliability costs were allocated on a 4-CP basis in Dr. Andersen's analysis. Dr. Andersen pointed out that as HL&P's capacity mix changed, i.e., became more highly dependent on less reliable non-gas fired capacity, the company increased its reserve margin from 15 percent to 20 percent stating that such is appropriate given the increasing level of coal, nuclear, and lignite capacity in the overall capacity mix. Dr. Andersen testified that since the increase in the reserve margin results from the substitution of alternate fuels for natural gas, he classified 4.17 percent of reliability cost (.05 ÷ 1.20 = .0417) as energy related. (Id., at 23.)

For production construction work in progress (CWIP) included in this case, of which the Limestone and Malakoff units comprise over 99 percent, Dr. Andersen classified the CWIP balance between demand and energy using the 1985 construction cost for lignite capacity relative to the 1985 cost of combustion turbine units. As a result, 20.76 percent of the production component of CWIP was classified as demand, and 79.24 percent as energy. (Id., at 31.)

Dr. Andersen's analysis resulted in the following allocation factors for production plant:

Rate Class	CAPSUB Allocation Factors
RES	0.328640
MGS	0.257740
LGS	0.177690
LOS-A	0.069120
LOS-B	0.142340
PU	0.022790
SPL	0.001540
GL	0.000150

Several parties presented testimony in opposition to the CAPSUB or energy based allocation method: TIEC, DOE, Champion, U.S. Steel/USX and HL&P. TIEC witness Jay B. Kennedy presented a detailed discussion of the general concepts of energy allocation of production plant and the reasons he deems such to be an inappropriate methodology. Mr. Kennedy testified that energy based allocations prefer to allocate the cost of baseload plants on the basis of energy consumption, on the premise that a substantial portion of fixed production costs (such as plant investment) should be so allocated because utilities build, or have built, units to reduce fuel costs rather than to meet peak demand. According to Mr. Kennedy this premise confuses cause and effect. He noted that the effect of building a baseload unit is to reduce system fuel cost [with the cause being to meet peak demand]. (TIEC Ex. 8 at 3-4.)

Mr. Kennedy identified the following problems with energy allocation methods. First, such proposals generally contain a number of flaws and inconsistencies and are simply a proxy for marginal cost pricing since the methodologies produce allocation results which are indicative of the concepts suggested by marginal cost proponents. (Id., at 5.)

Second, CAPSUB assumes some cost standard (e.g., the cost of a coal unit or peaker) for reliability or demand which is utilized to distinguish between demand related and energy related costs. While different methods may be employed, all such approaches assume that all costs above the cost standard are energy related since the cost standard is allegedly the maximum necessary cost exposure to meet the peak. According to Mr. Kennedy this approach is usually completely arbitrary, and there can be extreme variations in the cost of baseload units which have little or nothing to do with operating costs. Resultingly, all cost variations or excesses are automatically assumed to be energy related. (Id., at 6-7.)

Third, the nature of the method is unrealistic. Mr. Kennedy testified that CAPSUB equates the cost of peaking units with the cost of meeting a load of one hour duration, which is defined as reliability. It is then assumed that baseload plants are built in lieu of intermediate units or peakers solely for the fuel savings benefits; when in reality such units may be built to satisfy peak demand, minimize cost, provide fuel diversity and have sometimes been mistakenly built. He noted that there have been expenditures for baseload nuclear plants which are not economically justified. To illustrate his point Mr. Kennedy noted that CAPSUB would assume that a $3,000/KW nuclear plant was built in lieu of $350/KW peaking unit due to fuel savings. Mr. Kennedy testified that on a 2500 MW plant, no one would spend $6,000,000,000 for the chance of saving that amount in fuel costs. (Id., at 7-8.)

Fourth, Mr. Kennedy testified, CAPSUB fails to consider the concept of life cycle cost analysis used in generation planning studies. CAPSUB assumes that all cost savings materialize in the first year and thus the kilowatt hours generated by the system already incorporate the fuel savings and should be charged the cost of the baseload unit; however, many of the benefits of the baseload unit do not materialize for many years into the future. (Id., at 9-10.)

Fifth, Mr. Kennedy testified that CAPSUB would imply completely inappropriate rates because as units are added to the system it suppresses the change in the structure of system costs and the price signal to consumers is distorted. In instances where variable costs decline and fixed costs increase (e.g., when STNP enters service), proper price signals would indicate that energy costs have declined while fixed costs have increased. However, under pure CAPSUB, the energy related portion of costs (and hence rates) would increase (or slightly decrease) while fixed costs would be the same. (Id., at 10-11.) Mr. Kennedy also noted that time-of-day (TOD) rates would not be feasible or effective under an energy allocation method because as charges are transferred from a demand to an energy basis, the demand component of the rates is reduced considerably and the off-peak energy component is raised. Accordingly, a disincentive exists for the customer to differentiate between on and off peak usage. (Id., at 11.)

TIEC witness Pollock also criticized the CAPSUB method for the reasons summarized below:

1. CAPSUB fails to appropriately recognize the trade-offs between capacity costs and operating costs.

2. CAPSUB advocates typically assume that any investment over and above the cost of a peaking unit is related to the objective of providing fuel cost savings and, therefore, should be allocated relative to "year-round" energy consumption.

3. By allocating baseload capacity costs to off-peak hours, some CAPSUB methods understate the cost of providing service during on-peak hours.

4. By failing to "de-average" the allocation of both capacity costs and operating costs, the cost allocated to a high load factor customer class could exceed the "stand-alone" cost of this class.

5. CAPSUB methods double count energy consumption: once by itself and a second time as a subset of the coincident peak.

6. The fact that the cost of new baseload units, in retrospect, may turn out to be significantly more expensive than the cost of a peaking unit does not have any relevance in determining cost allocation and rate design issues.

(TIEC Ex. 5 at 7-22.)

DOE witness Goins also criticized the classification of baseload plant costs as energy related costs. Mr. Goins testified that if generating units with lower installed costs, but higher energy costs, were substituted for baseload units with higher installed costs but lower energy costs, expected power supply costs would not be minimized over the specified time period; and a suboptimal capacity mix and an inefficient pricing structure required to recover the costs of the suboptimal mix would result. (DOE Ex. 1 at 6.)

According to Mr. Goins, an energy allocation method in effect attempts to shift a greater portion of total system revenue requirements and increases caused by the addition of new baseload generating units to classes with relatively high load factors. (_Id._, at 7.) He noted that to be logically consistent:

> . . . those who argue for classifying some or all production plant costs as energy-related costs should support the use of replacement costs to value all production plant and the use of a probabilistic allocation methodology that reflects the demand for (capacity) and relative use of (energy) each generating unit by each class. Such valuation and allocation procedures would remove the vintage or class-specific pricing aspects of reclassifying production plant costs and ensure that higher load factor classes would get the major portion of reliability and lower power cost benefits of new baseload units over the operating lives of such units. If proponents of reclassifying baseload plant costs as energy-related costs fail to support these valuation and allocation procedures, we must conclude that the principal objective of reclassifying production plant costs is to shift cost responsibility for newer, more expensive plants to higher load factor classes.

(*Id.*, at 7.) According to Mr. Goins if production plant costs were incurred solely to provide cheaper energy as opposed to meeting load, then the costs could justifiably be classified as energy related costs. (*Id.*, at 8.)

Champion witness Eisdorfer testified that CAPSUB does not conform with the constraining realities prevalent in the electric utility industry. He noted that the selection of an appropriate generation mix for a utility involves several considerations, including:

a) ability to satisfy annual system peak demand,
b) unit response times to satisfy changing load conditions,
c) fuel availability,
d) siting considerations,
e) regulatory restrictions, and
f) political considerations.

(Champion Ex. 1 at 7-8.)

Mr. Eisdorfer testified that regardless of the generating mix of a particular utility, all production plants have fixed cost components, which by definition do not vary with the number of kilowatt hours produced. Rather, fixed costs tend to be level from year-to-year. He testified that:

> Production and transmission fixed costs are related to peak demands because it is the need to instantaneously meet this demand in a reliable manner that determines the size of a utility's generating and transmission facilities. Consequently, the investment in the production and transmission plant, as well as the fixed costs associated with that investment, should be classified within a cost-of-service study as being demand-related.

(*Id.*, at 9.)

Using several equations Mr. Eisdorfer illustrated his position that the utilization of a partial energy allocator tends to create a situation where it is in a class' best interest to have a poor load factor relative to the system load factor; the result being that system cost maximization is encouraged while efficiency is discouraged. (*Id.*, at 9-13.)

Mr. Eisdorfer further testified that under such a method the average coincident peak demand for a class may exceed that class' actual maximum demand imposition. (Id., at 13-15.)

Finally, Mr. Eisdorfer testified that if the additional capacity cost of a baseload unit (relative to a lower capital cost unit) is to be treated within a cost of service study as being energy related, it is equally valid to treat the additional running cost of a lower capital cost unit (relative to a baseload plant) as demand related. Therefore, a portion of fuel costs associated with lower capital cost units would have to be allocated on a demand basis, which would reduce the cost responsibility of high load factor classes and increase the cost responsibility for low load factor classes. (Id., at 16-17.)

U.S. Steel/USX witness Moore testified that it is absolutely inappropriate to allocate production plant on an energy basis because:

1. While fuel costs are considered by a utility in selecting the type of unit to construct, such costs are by no means the only, or even key, determinant in the decision-making process.

2. The allocation of capacity related production costs on an energy basis results in inequity in class revenue requirements; which can theoretically be corrected, but is extremely difficult to do accurately.

3. Allocating production plant on an energy basis results in an increase in the cost assigned to off-peak energy and a reduction in the cost assigned to energy consumed during peak periods. This fact tends to encourage on-peak energy consumption and increase total system peak demand, thereby hastening the need for construction of additional capacity.

4. High load factor customers that are adversely impacted by an energy allocation of production plant are also some of HL&P's largest customers, and some of these customers may have alternatives to

continued purchases from HL&P in the event that electric rates become intolerably high. The loss of significant amounts of industrial load would result in increased rates to all other customers.

(U.S. Steel/USX Ex. 1 at 13-19.)

On rebuttal HL&P witness Edwards focused on the CAPSUB proposal submitted by OPC in this case. Mr. Edwards testified that OPC witness Andersen's method is a drastically abbreviated version of the method he [Edwards] developed in 1978-1979. He noted that the abbreviations have resulted in fatal flaws and unreasonable results through both conceptual and methodological errors. (HL&P Ex. 56 at 16.) According to Mr. Edwards the problems with Dr. Andersen's analysis are as follows:

1. It is "woefully incomplete." According to Mr. Edwards the rendition of a set of replacement costs for various types of capacity make up a very small part of the correct analysis. More important, he noted, are the current fuel costs because these costs measure the potential to substitute capital for fuel in the first place. Dr. Andersen fails to take this into account. Mr. Edwards pointed out that the proper way to recognize the mismatch between theoretical capital costs and real fuel costs is to determine the capital costs based on the actual fuel costs, thus measuring the potential for capital substitution which exists. (Id., at 16-17.)

2. Dr. Andersen failed to perform the study on a time-differential basis. According to Mr. Edwards CAPSUB is first and foremost a time-differential costing method. (Id., at 18.)

3. By relying on the approach he used, Dr. Andersen performed a simplistic static analysis, when such is not representative of the real world. (Id. at 18-19.)

4. Dr. Andersen attempted to adjust his costs for HL&P's increased reserve margins (from 15 percent to 20 percent). However, Mr. Edwards

testified, what he has actually done is to discount both his demand and energy cost figures, and the demand costs have received the lion's share of the discount. According to Mr. Edwards the calculated demand should have been increased by the full 20 percent because: (a) the motivation ascribed to the change was primarily for reliability, not generation of energy; and (b) to make the reassignment Dr. Andersen has departed from cost-causation. (Id., at 19-20.)

5. Dr. Andersen failed to check his logic with the simple application of incremental analysis: the impact of a change in peak load, energy use, or both, on total cost. According to Mr. Edwards, had such a check been performed Dr. Andersen would have recognized that a change in energy use means, first and foremost, a change in fuel cost which might or might not be susceptible to being replaced by a change in capital cost. Whether it would, and how much, depends on the fuel cost in question and the time of the energy use in question. (Id., at 20.)

Finally, Mr. Edwards described the original CAPSUB method he developed in 1978-1979 and addressed the ways in which it differs from the approach utilized by Dr. Andersen. (Id., at 21-25.) Mr. Edwards noted that the method is complex, but it cannot be simplified without sacrificing the attribute of completeness. (Id., at 25.)

[26] f. Review and recommendation. As the foregoing discussion indicates, there are several ways to go about allocating production capacity costs among the various classes. No one method is perfect, and all have some positive aspect(s) and drawback(s); some more than others. It also bears noting that, understandably, it is not atypical for parties to urge the most self serving method in any given rate case. For discussion purposes the examiners have attached a chart marked Examiners' Ex. 8 which sets forth a comparison of the various options for allocating production capacity costs in this case. While, as pointed out by the parties, an appropriate cost allocation methodology should consider several factors such as tracking costs, recognizing off-peak usage, etc., also important are the results produced by the method. For reasons which

will be discussed below it is the examiners' opinion that the PONM methodology proposed by HL&P is a reasonable and appropriate methodology for allocating production capacity costs in this case.

A major issue herein is whether any portion of production capacity costs should be classified as, and allocated on the basis of, energy. Some argue that these costs should never be allocated on the basis of energy because they are incurred to meet peak demand and should therefore be classified as capacity related and allocated on a demand basis. Some argue that the classification of a portion of these costs as energy is appropriate if the costs were incurred for the purpose of effectuating fuel savings. The examiners agree that the primary driving force in generation planning is the ability to meet demands when they occur. Normally, if a utility's load does not indicate that additional capacity is needed, seldom would a generating unit be built for the sole purpose of fuel savings. Generally, when the decision is made that additional capacity is needed, factors such as the type of unit and energy considerations come into play. However, there may also be instances when the primary driving force for construction of new plant includes factors other than the need to meet increased demand. In this regard OPC pointed out in brief the following exchange which took place at the hearing during Dr. Guy's testimony:

> Q. Now, during the 10 year period in question 1976-1986 when Dr. Guy was HL&P corporate planner , were utilities in Texas, including HL&P, building only to meet the need for increased capacity?
>
> A. Houston Lighting & Power Company certainly was building for other reasons. I can't attest to other companies bases.
>
> Q. What would those other reasons be?
>
> A. Primarily, particularly beginning in the latter part of the seventies, to increase the fuel diversity and reduce the reliance on what was thought to be then very high, expensive natural gas prices.
>
> Q. Now, if a utility were to build for fuel diversification and not simply to meet the need for additional capacity, could it be an anticipated result that reserve margins would go above the target reserve margin?

> A. The target reserve margin is primarily one of reliability. So, therefore, you may have high reserves to accomplish other objectives; namely, keeping costs lower by building the base load non-gas and oil-fired equipment.

(Tr. at 3407, and OPC Brief at 8.)

In the examiners' opinion energy considerations are currently important in the generation planning process. It is reasonable to utilize a methodology which recognizes both peak demand requirements and energy consumption. While the primary emphasis in generation planning may be on meeting peak demand requirements, customers remain on the system during off peak periods, and energy usage characteristics are a reasonable consideration. However, aside from the numerous criticisms of the CAPSUB method discussed above, the examiners were not convinced that the extreme result of the CAPSUB method, which allocates a significant portion of production costs on the basis of energy, actually comes close to tracking costs. The CAPSUB method utilizes a cost standard or "yardstick" to determine the level of capacity costs to be assigned to demand and the amount to be assigned to energy. In this case the cost standard or yardstick is the combustion turbine or peaker. To the extent that a plant's capital costs exceed the capital costs of a combustion turbine, all of those excess costs are assigned to energy rather than demand. This would appear to indicate that capacity costs during non-peak periods throughout the year are, or should be, no more than the capital costs of peaker units. In the examiners' opinion this is unlikely especially since it would not be reasonable or economical to continuously operate peaker units throughout the year. It would appear that while it may be desirable for an allocation methodology to account for energy considerations, such seems excessive and out of line with reality under the CAPSUB method. Accordingly, while the examiners believe some weight should be given to energy, such should not be to the extent proposed by OPC.

The examiners agree with TNP witness Schuman's reasoning that among other things the 4-CP A&E method allocates capacity costs giving consideration to peak demand and energy usage characteristics, but the accuracy of his analysis is questionable. Mr. Schuman purported to use the 4-CP A&E method used by the Commission staff. However, such does not appear to be the case. Certain flaws were pointed out by HL&P witness Purdue as noted in the above discussion. Further, the staff performed its 4-CP A&E analysis for purposes of allocating transmission costs but these factors differ substantially from those calculated by Mr. Schuman. According to Mr. Rudolph the 4-CP A&E method used by the staff in this case is consistent with the methodology used by the staff in the past. (Tr. at 4998.) Given that Mr. Schuman himself claimed to have used the staff's methodology the examiners can only conclude that Mr. Schuman's calculations are flawed. It is noted that the results of Mr. Schuman's analysis are similar to the results reached under Dr. Andersen's CAPSUB analysis.

The examiners therefore do not recommend that Dr. Andersen's CAPSUB method or Mr. Schuman's 4-CP A&E method be adopted in this case. However, another method may merit consideration by the Commission. HL&P witness Purdue presented production allocation factors utilizing the 4-NCP A&E method. HL&P witness Edwards also testified that should the Commission desire to recognize the concept of energy cost, the 4-NCP A&E approach is most appropriate. Given the examiners' opinion that some recognition of energy is desirable in an allocation methodology, consideration was given to recommending the approval of the 4-NCP A&E method. However, from the record the examiners are currently unable to gauge the impact on the various classes which would result. As will be discussed below HL&P's cost study moves all classes towards unity. The examiners have, with certain modifications accepted HL&P's cost study. Although a mere comparison of the 4-NCP A&E factors with those calculated under PONM is not necessarily conclusive, such comparison indicates that under the former method more costs are shifted to the residential and public utility classes, which may result in a move away from unity. Depending on the magnitude of the rate increase (or decrease) ultimately awarded in this case, these factors may not be crucial and the Commission may wish to consider utilizing this allocation method. However, the examiners do not at this time recommend approval of this method, being unsure of the resulting impact.

The near peak method proposed by TIEC reflects peak responsibility concepts which opponents of energy allocators believe should be reflected in production allocators. However, the selection of the load to be deemed peak (load within a specified range of the annual peak) is totally subjective. In this case the utilization of loads which lie within five percent of annual system peak results in costs being shifted away from the industrial class and to the residential class. This method also allocates no production costs to the street and protective lighting (SPL) and guard light (GL) classes. In the examiners' opinion since all customer classes are jointly responsible for system costs all year round, all should contribute proportionately to demand during any given period.

The 4-CP method urged by Champion also focuses on peak responsibility and has the advantage of being less subjective in application than the near peak or PONM methods. However this method also allocates no production costs to the SPL and GL classes.

The PONM method proposed by HL&P is based on a detailed cost of service study. While the method is complex and requires a lot of input data, it is data that HL&P has available. HL&P's PONM method allocates some portion of production costs to each customer class. Although it is argued that the 4-CP method is less subjective than PONM, the results actually achieved in this case are close to those achieved utilizing 4-CP; so close in fact that one party urging the 4-CP method accepted HL&P's PONM method. This would appear to indicate that the subjectivity inherent in the PONM method has had a minimal impact in this case. Finally, while it is argued that the PONM method is subject to manipulation of input to get a predetermined result, so are most of the other methodologies proposed in this case. Based on the record herein the examiners recommend approval of HL&P's PONM method for allocating production capacity costs.

Finally, the examiners disagree with City of Houston witness Ileo that the interruptible service should be identified as a separate class for purposes of the cost of service study and cost allocation. The nature of the interruptible service is different from firm service as this load can be interrupted anytime circumstances deem such to be necessary. The fact that interruptions are few does not change this; the fact remains that such interruptions can occur at any time. As pointed out by TIEC on cross-examination, one acquires fire insurance for one's home each year regardless of whether a fire has occurred in the past. Even if a fire never occurs, the possibility of such still exists and insurance will still be purchased. (Tr. at 4206.) In the examiners' opinion interruptible service should not be treated in the same manner as firm service.

Further, as explained by Mr. Purdue, the manner in which HL&P treats the interruptible (and standby) service revenues reduces the overall revenue requirements of the firm service customers. The examiners therefore do not recommend that HL&P be required to identify the interruptible service as a separate class for cost allocation purposes.

2. Production O&M Expense

HL&P classified reconcilable fuel expense included in Accounts 501, 547 and 555 as energy related costs. HL&P directly assigns these expenses to customer classes to match fuel revenue. HL&P also classified maintenance expenses in Accounts 512, 513 and 553 as energy related costs. These expenses were allocated to the customer classes on the basis of test year generation level MWH sales. The remaining production O&M expenses were classified as demand related costs and allocated on the basis of the PONM method. (HL&P Ex. 3, Schedule P-7.C.)

DOE witness Goins testified that HL&P's classification of production related O&M expenses is a relatively standard and acceptable classification of such costs. (DOE Ex. 1 at 5.)

Champion witness Kalcic disagreed with the company in two respects. First, Mr. Kalcic testified, test year fuel expense should be allocated on the basis of test year generation level MWH sales [adjusted for losses] as this provides a more accurate reflection of fuel cost imposition on the HL&P system. (Champion Ex. 2 at 12-13.) Second, Mr. Kalcic disagreed with HL&P's classification of production maintenance expenses associated with electric plant

(Accounts 513 and 553) as energy related. Mr. Kalcic testified that these expenses should be classified as demand related because: (1) they are largely preventive in nature; (2) the periodic scheduled maintenance of generators is prompted by the fact that the utility must be able to immediately respond to the system demands; and (3) production capacity is dictated by the magnitude of the system peak demands. (Id., at 13.)

On rebuttal Mr. Purdue testified that the allocation of fuel expense in the manner proposed by Mr. Kalcic results in a mismatch between fuel expense and fuel recovery. According to Mr. Purdue fuel expense should be allocated to rate classes such that it equals the fuel recovery charge included in the rates. (HL&P Ex. 55 at 6.)

OPC witness Andersen allocated system dispatch expense, fuel expense, purchased power energy charges and capacity charges for non-firm cogeneration on the basis of loss adjusted energy. (OPC Ex. 89 at 24.) Dr. Andersen testified that the procedure utilized to allocate non-fuel O&M expenses was similar to that applied to energy related capacity costs, specifically:

> For each generating station, maintenance and operating expense was distributed across units in proportion to unit capacity. For each generating unit, costs were then allocated to months. Operating expense was allocated in proportion to each month's share of annual hours of operation, and maintenance expense in proportion to monthly shares of annual net generation. After aggregating cost by month, allocation to classes was accomplished on the basis of class contribution to total energy requirements within each month.

(Id.) Additionally Dr. Andersen allocated capacity payments to the Cities of Austin and San Antonio on the basis of class contribution to coincident peak during the four summer months. He noted that capacity payments for firm cogeneration were allocated using the composite allocator for production plant in service. (Id., at 24-25.)

The examiners find HL&P's classification and allocation of production O&M expense to be reasonable and recommend approval thereof with one exception; that being the classification of maintenance expenses in Accounts 513 and 553 as energy related. The examiners concur with Mr. Kalcic that since these maintenance expenses are incurred for preserving the operating efficiency and physical condition of the electric plant, thus enabling the utility to meet the system demand, it would appear more appropriate to classify such costs as demand related. The examiners therefore recommend that Mr. Kalcic's proposal to reclassify these expenses as being demand related be adopted.

C. Transmission Cost Allocation

This functional classification generally relates to that portion of utility plant used to transmit electric energy in bulk to other principal parts of the utility's system or to other utility systems; or to expenses related to the operation and maintenance of transmission plant. There is little, if any, disagreement that peak usage patterns are important in transmission system planning and that this should be recognized by the allocator used. In this regard several parties proposed the utilization of the same allocators for both production and transmission costs.

For purposes of the cost of service study HL&P apportioned its transmission lines between allocable and assignable plant, depending on their use. The assigned transmission line investment primarily includes short spur lines used to connect large industrial customer loads directly to the transmission system. HL&P directly assigned these lines to the large industrial customer class since they serve a single rate class and the purpose of these lines is not the transmission of bulk power. (HL&P Ex. at 31-32.)

[27] HL&P's remaining transmission lines were allocated utilizing the 4-CP allocation method. As explained in Section XI.B. above the 4-CP method, a variant of the peak responsibility method, determines the peak hour for each of the four months with the highest system peak demand. The separate class loads are summed for these four hours and averaged. The resulting class averages are summed and respectively divided by the total to determine class responsibility. (Id., at 29 and 32.) Mr. Purdue testified that the PONM method was not used to allocate transmission capacity costs because it was designed for generating equipment and therefore is not appropriate for the static (so to speak) nature of the transmission system. (Id., at 29.)

Mr. Purdue testified that certain major distribution substations serve, at least in part, a transmission function; therefore the functionalization of these distribution substations was accomplished in the same manner as for transmission substations. He noted that land and land rights were functionalized in proportion to the treatment accorded the accounts to which the land and land rights are principally related. (Id., at 32.)

The City of Houston and DOE witnesses implicitly, and U.S. Steel/USX and Champion witnesses explicitly, supported the use of the 4-CP method to allocate demand related transmission costs. Champion witness Kalcic employed the same reasoning for allocating demand related transmission costs on a 4-CP basis as he did with regard to demand related production costs. (Champion Ex. 2 at 9-11.)

U.S. Steel/USX witness Moore testified that because the factors influencing transmission planning are demand related, transmission plant should be allocated on the basis of peak demand, therefore the 4-CP method is appropriate. (U.S. Steel/USX Ex. 1 at 21-22.) Mr. Moore testified that the decisions regarding transmission plant are demand dependent because:

1. Any transmission system delivering power from one point to another must be sized so that it is capable of transmitting the peak demand required. Peak demand at the delivery point is the limiting determinant for capacity.

2. Energy considerations only influence transmission planning if there is some tradeoff between capital costs and variable hour-to-hour operating costs.

3. A transmission line of a given capacity and length costs no more to tie a solid-fuel plant into the utility's transmission grid than to tie a gas-fired plant to the grid.

(Id., at 21.)

Mr. Moore testified that one argument made in support of allocating a portion of transmission plant on the basis of energy is that: transmission facilities constructed to tie a baseload unit into the grid are energy-related to the same extent that the capital cost of the generating unit is energy-related; however this argument is without merit. He noted that even if a portion of production plant is deemed energy related, it does not follow that associated transmission facilities are also energy related. (Id., at 21.) Mr. Moore testified that:

> Most transmission facilities that tie generating plants to the grid serve purposes other than to merely deliver the output of the generating plant into the system. Generally, these transmission facilities also provide interconnections with other systems and/or alternatives to the utility's other transmission paths. These additional facilities thus serve to improve the reliability of the system. Arguing that an energy allocation of production plant logically requires a similar treatment for transmission plant is tantamount to asserting that the transmission lines in question are of no value unless the generating plant is running.

(Id.)

Mr. Moore further testified that the energy allocation argument invalidly presupposes that if the generating plant were built near the utility's load center, no transmission facilities would be required; when in fact substantial capital expenditures for switching facilities and protective equipment would be required irrespective of the type of fuel burned at the plant. Mr. Moore also pointed out that the cost of the substantial portion of transmission plant utilized merely to transmit power between various points has nothing to do with the type of fuel burned. (Id., at 25.) For these reasons Mr. Moore recommended rejection of any energy based allocation of transmission plant.

TIEC also determined that transmission costs are demand related and that they should be allocated accordingly. Using the same analysis as applied to the allocation of production capacity costs, TIEC witness Thomas recommended approval of the near peak method. (TIEC Ex. 7 at 9-13.)

OPC witness Andersen also utilized the same allocators for transmission costs as he did for production costs. Dr. Andersen testified that the principal benefits derived from the existence of a transmission network include: (1) allowing the integration of the load centers served by HL&P; (2) providing the opportunity for reductions in operating expenses and capacity requirements through interconnection with other utility systems; (3) allowing interconnections with other utilities which can serve as a substitute for the higher reserve margins that would be required for an isolated system since it is the equivalent of expanding the scale of the system. (OPC Ex. 89 at 26-27.) Dr. Andersen testified that the transmission network is an extension of and, to some extent, a substitute for investment in generating capacity and if the interchange benefit of reduced production O&M expense is viewed as ancillary, then transmission costs may be assigned by application of the same factors applicable to generation related fixed charges. Dr. Andersen noted that a broader method of allocation is to assign transmission cost in proportion to class responsibility for total generation. (Id., at 27.)

TNP and the Commission staff proposed the utilitization of the 4-CP A&E method to allocate transmission costs, although, as previously noted, their respective calculated factors differ. TNP, like TIEC and OPC, employed the same factors to allocate transmission costs as applied to production costs; noting that if production costs are allocated to the off-peak loads, so too should the transmission costs be allocated. According to Mr. Schuman the 4-CP A&E method allocates some costs to the classes which do not contribute to peak demand but do receive some of the benefits of the transmission facilities. (TNP Ex. 6 at 15-16.)

The staff's rationale for its proposed transmission allocator was similar to that of TNP in that the appropriate allocator should consider both system planning and usage characteristics. Regarding the former, staff witness Rudolph testified that since system peak demand is an important decisional factor in the transmission planning process, transmission capacity should be partially allocated on the basis of coincident demand usage. (Staff Ex. 28 at 8.) Regarding the latter, Mr. Rudolph testified that the transmission capacity allocator should encompass both peak and off-peak usage patterns to assure an apportionment of demand responsibility to all customer classes. (Id., at 9.) Mr. Rudolph calculated the following factors using the 4-CP A&E method:

Rate Class	Staff 4-CP A&E Allocation Factors
RES	0.368234
MGS	0.271879
LGS	0.170142
LOS-A	0.054812
LOS-B	0.105995
PU	0.027110
SPL	0.001626
GL	0.000201

From the evidence presented it would appear reasonable to employ the same factors for allocating transmission costs as are being utilized to allocate production costs. However, the examiners have recommended adoption of HL&P's PONM method for allocating production costs and the company had indicated that that method is inappropriate for allocating transmission costs. In the examiners' opinion the staff's recommended 4-CP A&E method is reasonable and should be utilized to allocate transmission costs in this case as it not only appears to track costs, but also allocates a portion of said costs to all customer classes. The 4-CP and near peak methods allocate nothing to the SPL and GL classes even though these classes use the transmission facilities. The examiners also agree with Mr. Moore that energy considerations are not important in allocating transmission costs. While the 4-CP A&E method is generally described as one which allocates partially on the basis of energy, such is not the basis for the examiners recommendation herein. Further, according to Mr. Edwards the 4-CP A&E method in which class excess demands are based on CP demands (the staff method) cannot be accurately described as a method reflective of energy responsibility goals. The examiners therefore recommend adoption of the staff's allocation factors set forth above.

D. Distribution Cost Allocation

HL&P utilized the 4-CP (four monthly distribution system peak hours) to allocate capacity related distribution plant. (HL&P Ex. 10 at 30.) No party opposed HL&P's distribution allocators in this case, although OPC witness Andersen expressed concerns regarding certain aspects of HL&P's distribution cost allocation which will be discussed below.

As noted in Section XI. C. above, certain distribution substation plant investment was reclassified to the transmission function for reasons previously stated; of the remaining distribution substation plant, that portion used to serve a single rate classification was, where accurate costs could be sufficiently obtained, directly assigned. The balance of distribution substation plant was allocated to rate classes in proportion to the class demand at the 4-CP distribution system peak to the total 4-CP distribution peak demand. (Id., at 32-33.)

HL&P's overhead distribution lines were classified and allocated in the following manner. This customer related plant--the minimum plant investment needed to connect a customer and provide for some relatively small level of usage--was classified as such based upon a hypothetical minimum system (which provides area coverage and is based on minimum conductor size and pole class), which Mr. Purdue described as follows:

> The procedure to derive the cost of the minimum system is to price the components on a current cost basis. The current cost is then reduced to an original cost value by multiplying the ratio of original cost to current cost for the total distribution line account. Finally, this value is reduced to a net original cost value by multiplying by the percent depreciation applicable for this account. These costs are then allocated to classes served at distribution based on customer count.

(Id., at 33-34.) The remaining overhead distribution lines were allocated following the 4-CP distribution peak method. (Id., at 34.)

HL&P identified four categories of underground facilities (lines and conduit): underground (U.G.) network, U.G. getaways and street dips, U.G. service from terminal poles, and residential underground. The U.G. network system was allocated based upon class contribution to system peak demand by the classes served by the network; while U.G. getaways and dips, and service from terminal poles were allocated on the basis of class contribution to the 4-CP distribution peaks. Residential underground was directly assigned to that class. (Id.)

HL&P's line transformers were directly assigned based on available data in the company's transformer load management program (TLM); which program provides an estimate of the transformer's peak load based upon energy supplied (identifiable by rate class) through the transformer. (Id., at 34-35.) The cost was then assigned using the "zero intercept" method which Mr. Purdue described as follows:

> The zero intercept method uses a least squares regression analysis of the installed cost of transformers. The values on the horizontal axis are the various sizes of transformers while the values on the vertical axis are the cost by size of the transformer. The intercept of the regression line with the vertical axis is the cost of a theoretical zero capacity transformer. The zero intercept unit cost is then multiplied by the number of line transformers to obtain the customer related cost.

(Id., at 35.) The capacitors were allocated to distribution customers based upon the 4-CP distribution system method. (Id.)

OPC witness Andersen accepted HL&P's allocation of poles, lines and transformers, but not without criticism. According to Dr. Andersen he proposed no adjustments in this case because he did not have the opportunity to develop alternative allocation factors. (OPC Ex. 89 at 31.)

Dr. Andersen's first criticism relates to HL&P's use of the "minimum system" concept utilized to classify overhead distribution lines as customer related plant. Dr. Andersen testified that the principal determinant of the number of poles in service and miles of distribution line is not the number of customers served; rather the scope of the distribution network is a function of the geographic size of the territory served. (Id., at 28.) According to Dr. Andersen since a certificated utility has an obligation to serve, the size of its distribution network is not related to either the number of customers or the demands they impose on the system. Rather, he testified, the distribution network should be characterized as a general overhead cost incurred as a result of certification; and as such is unallocable. (Id., at 28-29.)

Dr. Andersen further testified that even if the Commission finds the minimum system concept to be acceptable, HL&P's allocation of Accounts 364 (poles, tower & fixtures) and 365 (O.H. conductors & devices) is incorrect because the minimum system, as designed by HL&P, is not without load carrying capability. Therefore, if costs in excess of the cost of the minimum distribution network are allocated on the basis of unadjusted demands, then the fact that a portion of each customer's demand is served by the capability of the minimum system is neglected. (Id., at 29.)

Dr. Andersen next focused on HL&P's use of the "zero intercept" to allocate line transformers; testifying that said methodology is not reasonable because it is an artificial and unnecessary abstraction. (Id., at 30.) He further testified that if there is a reason to identify minimum system costs, then the appropriate procedure is to charge all customers a pro-rata share (pro-rata because the number of customers generally exceeds the number of transformers) of the cost of a minimum transformer and to credit each customer's demand by a pro-rata share of the load carrying capability of that transformer. Otherwise the same inequities occurring from the application of the minimum system concept to the allocation of lines and poles results. (Id., at 30-31.)

In its brief OPC urged the Commission to order HL&P to modify its distribution cost analysis in future cases to: (1) adjust demands to reflect the load carrying capability of minimum size facilities, and 2) charge all customers a pro rata share of the cost of a minimum transformer and credit each customer's demand by a pro-rata share of the load carrying capability of that transformer. (OPC Brief at 35-36.)

The examiners recommend the adoption of HL&P's proposed allocation of distribution costs in this case. Regarding OPC's proposal set forth above, the examiners do not believe a utility should be required to file any particular cost analysis. Rather, the utility should be allowed to file the type of analysis it deems appropriate, an opportunity to litigate the matter should be afforded; and ultimately the Commission decides the appropriate method to be utilized; be it that proposed by the utility or an alternative one. Further, in this case the matter has not been fully litigated. Dr. Andersen did not in his testimony propose the relief sought by the OPC in its brief, he merely pointed out methods he deemed preferable to those employed in this case. However, at this time the examiners do not know whether or not Dr. Andersen's suggestions are more appropriate, or if a method different from that of HL&P and the OPC is in fact the most appropriate. The examiners therefore do not recommend that the OPC's request that HL&P be ordered to file a particular type of distribution cost analysis in future rate cases be adopted.

E. Administrative and General Expense (A&G) Accounts 920, 921, 922, 923, 925 and 926

HL&P allocated A&G expense accounts 920, 921, 922, 923, 925 and 926 to O&M expense on salaries and wages by account. (HL&P Ex. 3, Schedule p-7.C, Pg. 4.)

The staff allocated the above accounts on a composite payroll basis. (Staff Ex. 30 at 3.) Mr. Rudolph testified that this allocation is appropriate because the expenditures associated with the expense accounts 920, 921, 922, 923, 925 and 926k are incurred as a result of providing support for HL&P's entire electric system. Therefore, it is necessary to derive an allocator which reflects the nature of the expenditures, i.e., one created on a composite basis. (Id., at 2-3.) Mr. Rudolph testified that this requires a determination of which type of expense best captures the nature of the costs being allocated. In his opinion, the above accounts are wage and salary related and should be allocated on a composite payroll basis. (Id., at 3.)

OPC witness Andersen testified that he finds no basis for the treatment of certain accounts, which include such items as administrative salaries (account 920) and outside services (account 923), as though they are exclusively related to payroll expense. (OPC Ex. 89 at 32.) Dr. Andersen therefore performed an account-by-account analysis of A&G expenses. (See OPC Ex. 89, Appendix B.) Costs which were classified as labor or plant related were allocated accordingly. General overhead costs were allocated to classes in proportion to class responsibility for the aggregate of production, transmission, distribution and customer cost. (Id., at 32.)

The examiners find that the staff's rationale and proposed treatment of accounts 920 (general officers & executive salaries), 921 (office supplies and expenses), 922 (administrative expenses transferred), 923 (outside services employed), 925 (injuries and damages), and 926 (employee pensions and benefits) appear reasonable; and was neither rebutted by the company through testimony, nor challenged in brief. The examiners therefore recommend that the foregoing accounts be allocated on a composite payroll basis.

F. Uncollectible Expense (Account 904)

HL&P directly assigned the uncollectible expense to rate classes on the basis of a Credit Department survey of delinquencies. (HL&P Ex. 10 at 38.) Mr. Purdue testified that the survey reviewed the "delinquencies" on a class by class basis and established ratios to the total delinquencies. The uncollectible expenses were then allocated back to those classes by the percentages developed. (Tr. at 3768.) On cross-examination Mr. Purdue acknowledged that there is a difference between delinquencies and uncollectibles, but no study was performed to determine if uncollectibles follow delinquencies by rate class. (Tr. at 3788.) Mr. Purdue later testified that while his written testimony uses the word "delinquencies," he meant "write-offs" or "uncollectibles." (Tr. at 3892.)

Mr. Purdue testified that the survey he relied upon in this case was based on 1983 data; the latest data the company has required to be compiled. (Tr. at 3898.) The results of the study and the percentages (of expense) assigned to the classes are illustrated on HL&P Ex. 3, Schedule P-7.B., page 54. The 1983 survey indicated that the following classes contributed to the 1983 delinquencies by the approximate percentage (rounded) shown: 81 percent for the residential class, 18 percent for MGS, 1 percent for LGS and .01 percent for SPL. (Tr., at 3896.) These percentages were utilized to assign uncollectible expense to these rate classes in this case.

Mr. Purdue also testified that data on uncollectibles was compiled for the years 1976, 1977 and 1979 (Tr. at 3893) which reflected the following percentage uncollectibles. For 1976, uncollectibles were shown as: 59 percent for residential and 41 percent for MGS. The 1977 survey reflects uncollectibles by class of: 75 percent for residential and 25 percent for MGS; and for 1979 of: 79 percent for residential, 15 percent for MGS, one percent for LGS, and five percent for LOS-A. Mr. Purdue noted that he believed the LOS-A uncollectible to be a Chapter 11 [bankruptcy] which was later reversed. (Tr. at 3896.)

Mr. Purdue further testified that while in general uncollectibles are a function of revenues, in this instance revenue related costs should not be allocated on the basis of revenue. (Tr. at 3891-3892.) Rather, he testified, uncollectible costs should be assigned to those customer classes that cause the cost to be incurred. (Tr. at 3858-3859.)

Several parties presented arguments in their briefs in support of HL&P's treatment of uncollectible expense. (See TIEC Brief at 16, Dow Brief at 9-11, and Champion Brief at 28-30.)

The staff disagreed with HL&P's treatment of uncollectible expense. Mr. Rudolph testified that HL&P cannot demonstrate that the bad debt expense is caused by current customers because the customers who caused this expense to be incurred are no longer connected to the system. He further testified that because the sources of the expense are previous, not current, ratepayers, it is reasonable to characterize bad debt or uncollectible accounts as a cost which is external to the system. (Staff Ex. 28 at 11.)

Mr. Rudolph testified that two alternatives of recovering external costs are:

1. Track the customers who caused the bad debt expense. This, however, may not be feasible as it is difficult and expensive to locate and prosecute the bad debt customers.

2. Treat the bad debt expense as a social cost to be shared by all customers connected to the system; basing the allocator on operating revenues. This would be appropriate as bad debt expense is generally perceived to be related to total revenues.

(Id., at 11-12.) Mr. Rudolph recommended that the latter alternative be adopted, and that uncollectible expenses be allocated according to each class' contribution to operating revenues. (Id., at 12.) Responding to why it is reasonable to treat uncollectible expense as a social cost Mr. Rudolph testified that:

> The main reason a social cost treatment is reasonable is that while it may be true that certain customer classes pose a higher risk, it is equally important to recognize that the overwhelming majority of customers within both high and low-risk classes are likely to be reliable ratepayers. Hence, if these individuals are to be treated in an equal and uniform manner, it is essential to develop an allocator which acknowledges the systemwide nature of bad debt expense. Any other treatment is discriminatory because creditable customers are classified on the basis of customer class conduct instead of individual merit. The main point is that a social cost approach is preferable because it attempts to treat equals alike; that is, in a uniform and equitable manner.

(Id.) He also noted that such treatment is consistent with past Commission rulings on this issue.

[28] The examiners concur with the staff's reasoning and proposed treatment of uncollectible expense. Bad debt or uncollectible expense can potentially be caused by any rate class. Further, the expense is not caused by, nor is it the fault of, the current customers. The cost causers have left the system. Bad debt expense is a cost of doing business. It differs from most expenses in that the uncollectible expense does not benefit, nor is it incurred for the purpose of serving, current customers. To minimize the negative impact on any one class, the examiners believe it is reasonable to spread this expense to all customers. It is argued that this treatment could result in substantial costs being assigned to the residential class, if for example, an industrial customer is the source of such expense, because the costs would be shared by all rather than being borne only by the industrial class. This may be true, but it is the

examiners' opinion that bad debt expense should be borne by all customer classes regardless of where the expense was generated. This avoids penalizing customers in a particular class (who pay their bills) for the wrongful actions of others. The examiners therefore recommend that the staff's proposed treatment of uncollectible expense be adopted.

G. Sales Expenses (Accounts 911, 912, 913, 915 and 916)

HL&P directly assigned these expenses to the rate classes on the basis of an analysis prepared by the company's Commercial Department. (HL&P Ex. 10 at 38.)

The staff allocated these costs on the basis of total system revenues. Mr. Rudolph explained that:

> The main reasons why the staff allocated accounts 911, 912, 913, 915 and 916 on the basis of revenues is that, in general, these accounts are related to selling activities. Since a primary objective of selling activities is to generate revenues, the staff believes it is reasonable to allocate these accounts on a revenue-related basis; hence the application of the total system revenue allocator.

(Staff Ex. 30 at 2.)

The examiners note that the particular accounts at issue fall within the ambit of customer information expenses. These expenses are incurred for the benefit of existing customers; customers which HL&P apparently has the ability to identify. It is the examiners' opinion that if costs or expenses are incurred <u>for the purpose of serving</u> a particular class (or classes) and that class can be accurately identified, then there should be a direct assignment of said costs or expenses. Accordingly, the examiners recommend that HL&P's proposed direct assignment of Accounts 911, 912, 913, 915 and 916 be adopted.

H. State Gross Receipts Taxes

HL&P allocated gross receipts taxes based on revenue within cities, <u>i.e.</u>, revenue derived from incorporated areas as opposed to unincorporated areas. (HL&P Ex. 10 at 37.)

The staff allocated state gross receipts taxes on a revenue basis. (Tr. at 5016.) On cross-examination Mr. Rudolph testified that in his opinion all customer classes contribute to these taxes. He noted however that if such taxes are collected in a fashion similar to that of franchise fees[17] then he would allocate state gross receipts taxes on the same basis as he did for the franchise fees. (Tr. at 5017.) The staff did not allocate franchise fees to customers located in unincorporated areas. (Tr. at 4993.)

It appears to the examiners that state gross receipts taxes are incurred in the same manner as franchise fees; specifically such taxes are levied only on revenues collected within municipalities, and not on revenues derived from unincorporated areas. Thus, customers in unincorporated areas do not contribute to the incurrence of this expense. The examiners therefore recommend that HL&P's proposed treatment of this expense be adopted.

I. Revenue Distribution

1. HL&P

HL&P spread its proposed increase among the rate classes primarily on the basis of the cost of service study prepared by Mr. Purdue (which has been previously discussed). Mr. Standish testified that the rate increase was spread such that the classes' relative rates of return either remained at or were moved towards unity; specifically, all classes within three percentage points of unity were moved to unity, and those outside that range were moved toward unity. (HL&P Ex. 19 at 6.)

Mr. Standish further testified that one method by which to measure the degree to which rates are based on costs is to compare revenues at present and proposed levels to operating revenues at equal rates of return. (Id.,at 6-7.)

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[17]Franchise fees (or local gross receipts taxes) are those imposed on the utility by incorporated areas for the use of the right-of-ways in the cities' streets. (Tr. at 3763.) Providing service to customers in unincorporated areas does not contribute to this expense.

This comparison, based on HL&P's present and proposed rates is illustrated below:

Present Rates

Rate Schedule Description (1)	Operating Revenue (000's) (2)	Oper. Rev. Equal Rates of Return (000's) (3)	Ratio of Column (2)÷(3) (4)
Residential	1,280,080	1,270,742	1.01
MGS	920,033	902,108	1.02
LGS	546,829	576,088	0.95
LOS-A	201,902	200,506	1.01
LOS-B	411,208	411,003	1.00
TNP	69,271	64,264	1.08
Interruptible	17,524	17,524	1.00
SPL	25,380	29,650	0.86
GL	1,264	1,606	0.79
Total	3,473,491	1,473,491	1.00

Proposed Rates

Rate Schedule Description (5)	Operating Revenue (000's) (6)	Oper. Rev. Equal Rates of Return (000's) (7)	Ratio of Column (6)÷(7) (8)
Residential	1,258,088	1,257,090	1.00
MGS	883,483	870,091	1.02
LGS	517,929	533,089	0.97
LOS-A	170,818	170,354	1.00
LOS-B	354,652	354,618	1.00
TNP	63,752	60,764	1.05
Interruptible	19,950	19,950	1.00
SPL	30,625	33,186	0.92
GL	1,449	1,605	0.90
Total	3,300,746	3,300,747	1.00

(HL&P Ex. 19, Chart TRS-1.)

Other measures of cost based rates, Mr. Standish testified, are: (1) rate of return, and (2) relative rate of return index for each rate class. (Id., at 9.) These measures, calculated for HL&P's present and proposed rates, are illustrated on the following chart which shows that the return index for all classes either remained at or was moved closer to unity.

Rate Schedule Description (1)	Present Rates Rate of Return % (2)	Present Rates Index (3)	Proposed Rates Rate of Return % (4)	Proposed Rates Index (5)
Residential	8.7249%	1.03	12.3200%	1.00
Misc. General Service	9.1575%	1.08	12.7926%	1.04
Lg. General Service	6.5588%	0.77	11.2929%	0.92
Lg. Overhead Serv.-LOS-A	8.8526%	1.04	12.4149%	1.01
Lg. Overhead Serv.-LOS-B	8.5217%	1.00	12.3006%	1.00
Public Utility	11.1058%	1.31	13.8548%	1.13
Street & Protective Lgt.	5.1710%	0.61	10.3021%	0.84
Guard Lighting	-2.9928%	-0.35	7.0670%	0.57
	8.4950%		12.2962%	

(Id., at Chart TRS-2.)

2. City of Houston

Mr. Ileo testified that he utilized the following criteria for distributing the revenue requirements in this case:

> (a) the revenues from interruptible service (IS) should reflect its lesser quality as compared to firm service and, thereby, IS should not be expected to produce a ROR close to the system average ROR;
> (b) all service classes, to the extent consistent with other criteria, should be better-off under the city's revenue distribution than under HL&P's revenue distribution since the total revenue requirement of the company as determined by the city is significantly less than that requested by HL&P;
> (c) no service category should sustain an increase in its base rate revenues any greater than approximately 200 percent of the overall company base rate revenue increase or any less than approximately 50 percent of the overall company base rate revenue increase of about 9.2 percent; and
> (d) the ROR Index for each service category should move closer to 100 percent.

(City Ex. 58 at 6-7.) The application of these criteria to the city's proposed revenue requirement ($3.0877 billion) results in the following revenue distribution.

	Total Revenue Req.		Base Revenue Req.			
Serv. Class	Amount (000,000)	% Change	Amount (000,000)	% Change	ROR	ROR Index
RS	$1,165.5	(8.3%)	$812.6	7.9%	12.2%	105.3
MGS	811.2	(11.3)	515.0	7.9	12.6	108.5
LGS	473.7	(12.5)	263.0	16.0	10.9	93.9
LOS-A	162.0	(18.8)	76.7	8.8	12.6	108.5
LOS-B	327.7	(19.3)	150.5	9.7	12.3	106.4
IS	61.5	(16.0)	17.4	18.3	(1.4)	(11.9)
PU	59.3	(13.3)	38.5	4.3	14.1	122.1
SPL	25.5	0.8	22.7	7.6	7.5	64.5
GL	1.3	1.9	1.0	18.6	5.6	48.3
Total	$3,087.7	(11.08%)	$1,897.4	9.2%	11.6%	100.0

(*Id.*, at 7.)

3. DOE

Mr. Goins testified that overall HL&P's proposed revenue assignment represents a reasonable step in removing interclass subsidies and moving all classes closer to unity. (DOE Ex. 1 at 12-13.) Mr. Goins also testified that while additional adjustments might be made for the MGS class (with a relative ROR of 1.04) to further reduce the interclass subsidies, such might create "crossover" and revenue stability problems between the MGS and LGS classes. He also noted that further increases in revenues to the LGS rate class, over and above the company proposal, could result in an unacceptably high rate increase to the LGS customers. (*Id.*, at 13.)

Finally, Mr. Goins recommended against any further downward adjustment in revenues assigned to the LOS-A class. Mr. Goins testified that:

> Major sales and demand adjustments for this schedule have been included in the company's cost studies and estimated billing determinants. Additional reductions in the revenue responsibility

> assigned to this class are unjustified until the company and the Commission determine whether the company's proposed usage adjustments represent actual trends by customers in this class.

(Id.)

4. Champion

Mr. Eisdorfer utilized the results of Mr. Kalcic's cost of service study to evaluate HL&P's proposed revenue distribution. He testified that under HL&P's proposal the LOS-B class moves further away from cost compared to present rates, and the residential class which is currently providing a rate of return above the system average moves below the system average. (Champion Ex. 1 at 27.)

Mr. Eisdorfer further testified that currently the LOS-B class is providing the largest subsidy of any customer class, and such would be exacerbated under HL&P's proposal. He also noted that under the company's proposal the residential class would be a subsidized class. (Id.)

Mr. Eisdorfer testified that it is preferable to reduce HL&P's existing subsidies for the firm power classes in a uniform manner. Mr. Eisdorfer recommended a 50 percent reduction. (Id.) He further proposed that Rate ISA receive the system average percentage increase in base rate revenues; which, according to Mr. Eisdorfer, will tend to maintain the existing rate relationship between Rate ISA and the firm power rates. (Id., at 27-28.)

Mr. Eisdorfer testified that under his proposal no class receives more than 1.63 times the average percentage increase for the entire company. He noted that this proposal increases equity among the classes by moving each class towards equalized rates of return, and also lessens the potential for earnings instability which currently exists. (Id., at 28.)

5. TIEC

Mr. Pollock testified that HL&P's proposed revenue distribution is consistent with the objective of moving rates closer to cost. (TIEC Ex. 5

at 24-25.) He noted however that HL&P's proposal would not reduce all of the interclass subsidies based on the "near-peak" cost of service study. According to Mr. Pollock the interclass subsidies of the residential and LOS-B classes would be increased rather than decreased; therefore rates for these classes would not move closer to cost. He further noted that even where the interclass subsidies are reduced, the changes are neither systematic nor significant; therefore, the rates will continue to differ significantly from cost. (Id., at 26.)

Mr. Pollock proposed the systematic reduction of the interclass subsidy from each customer class; limiting such reduction so that the maximum increase will not exceed 1.5 times the average base rate percent increase. (Id., at 26.) However, Mr. Pollock testified, the increase allocated to the LGS class should be limited to 1.25 times the system average base rate percent increase because:

> An exception was made for the large general service class. Specifically, if the above criteria were applied, then the increase to this class would be about 1.5 times the system average base rate percent increase. As Mr. Thomas has noted, the cost-of-service study results for this class appear to be anomalous relative to the results of similar cost-of-service studies in prior HL&P rate cases. Generally, the results of the cost-of-service study should be fairly consistent from case-to-case. Thus, the large general service class rate of return should be close to or above the system average rate of return consistent with the results under the approved rates in the last rate case. Because of this anomaly, the rate of return of this class is understated and, consequently, the interclass subsidy is overstated. Therefore, the increase allocated this class was limited to only 1.25 times the system average base rate percent increase.

(Id., at 27.)

If the Commission approves a lower increase than requested by HL&P, Mr. Pollock recommended that the company be required to rerun the cost of service study, and the lighting classes should continue to be allocated the maximum possible increase--consistent with the concept of gradualism. He further testified that if the approved system-wide base rate increase is below 10 percent, then the increase to the lighting classes should not be less than 15 percent; and the increase to the remaining classes should be such that the current revenue subsidies are reduced by at least 20 percent. (Id., at 28.)

6. OPC

Dr. Andersen made two adjustments to HL&P's allocation of revenues. First, he reallocated interruptible base revenues and transmission facilities use revenues for consistency with his allocation of production and transmission plant. Second, he adjusted fuel revenues to reflect the $316,790,000 reduction resulting from the fuel factor change that occurred subsequent to the filing of HL&P's rate case. Dr. Andersen allocated this reduction in revenue on the basis of loss adjusted energy, grossed up for revenue related taxes and expenses. (OPC Ex. 89 at 34.)

Dr. Andersen recommended that the revenue decrease proposed by OPC be spread among the classes as follows. Revenues for all classes showing a revenue deficiency should be maintained at the present level, with the rate reduction being allocated to the relative share of the total reduction that would be required to equalize revenues and costs. (Id., at 35.) The effect of Dr. Andersen's recommendation is shown below:

Revenue Reductions by Rate Class

Class	Equalizing Reduction (000)	Percent of Total	Recommended Reduction (000)
Residential	$101,264	60.13%	$ 71,671
Misc. General Service	53,409	31.71	37,801
Public Utility	13,452	7.99	9,521
Guard Lights	289	.17	205
Total	$168,414	100.00%	$119,198

(Id.) Dr. Andersen noted that if the approved reduction is less than that proposed by OPC, the revenues should still be spread on the basis of the percentage shown above, with no net rate change for revenue deficient classes. (Id.) Dr. Andersen further noted that the above recommendation should apply whether the net reduction is in whole or in part the result of a reduction in fuel expense. According to Dr. Andersen the above chart shows that the base rates for the classes listed are too high relative to the remaining classes. He therefore recommended that any reduction in allocated fuel expense be offset by an equal increase in base rates for the LGS, LOS-A, LOS-B and street lighting classes, and that the net revenue reduction be allocated as shown by the above chart. (Id., at 35-36.)

7. TNP

Mr. Schuman focused his testimony on the rate of return on rate base allocated to TNP at HL&P's proposed system unity rate of return. Mr. Schuman testified that the following chart (taken from data in HL&P witness Standish's testimony) illustrates that TNP is being asked to subsidize certain other customer classes:

Rate Schedule Description (1)	Operating Revenue (000) (2)	Oper. Rev. Equal Rates of Return (3)	Revenue Difference (000) (4)	Ratio of Columns (2) and (3) (5)
Residential	$1,258,088	$1,257,090	$ 998	100.0794%
MGS	883,483	870,091	13,392	101.5391
LGS	517,929	533,089	(15,160)	97.1562
LOS-A	170,818	170,354	464	100.2724
LOS-B	354,652	354,618	34	100.0096
PU (TNP)	63,752	60,764	2,988	104.9174
SPL	30,625	33,186	(2,561)	92.2829
GL	1,449	1,605	(156)	90.2804
Totals	$3,280,796	$3,280,797	$ (1)	100.0000%

(TNP Ex. 6 at 17-18.) Mr. Schuman testified that a 13 percent return differential is unreasonable pursuant to Section 45 of PURA which states that: "No public utility may establish and maintain an unreasonable difference as to rates and service either as between localities or as between classes of service." (Id., at 19.) HL&P explained the basis for the relative rate of return to TNP in the following RFI (request for information) response:

> An explanation of how the proposed revenue increase was spread to the various rate schedules can be found on page 6 of 31 of the direct testimony of T.R. Standish. In establishing the proposed relative rate of return for TNP, consideration was given to the principles of economic efficiency, gradualism, revenue stability and revenue

erosion. As can be seen on page 8 of 31 of the direct testimony of T.R. Standish, TNP's relative rate of return was moved toward unity from 1.08 to 1.05. The relative rate of return of 1.08 is primarily due to the fact that the present TNP rate (revenue) was derived using TNP's load without a portion of it being supplied by Capitol Cogeneration. Since TNP has reduced their load on the HL&P system by approximately 300 MW, the allocation of capacity related costs associated with the 300 MW loss of TNP load was relative rate of return to unity would require an additional shift in revenue of approximately three million dollars to other rate classes. The company feels that the previously mentioned principles should be considered when moving TNP's relative rate of return in order for other ratepayers not to be unduly burdened.

(Id., at Ex. AHS-4.) Mr. Schuman testified that TNP should not be penalized for complying with the Commission's position that cogeneration should be encouraged. He further noted that as recently as HL&P's last rate case, Docket No. 5779, the company indicated that HL&P's other customers would benefit from TNP's minimization of peak demand requirements. (Id., at 19-20.)

Mr. Schuman further testified that another factor indicating the unreasonableness of the rate of return proposed for TNP is that it is not the loss of TNP load which is of greatest significance to HL&P, but instead the pending loss of DOW's load. (Id.) Referencing testimony of an HL&P witness in another case, Docket No. 6064, Mr. Schuman pointed out that the company indicated that "In terms of direct effect, the single most significant impact has been the announced intention of Dow Chemical Company to eliminate all of its purchases." (Id., at 21.)

Finally, Mr. Schuman testified that HL&P has not historically proposed a rate of return higher than system unity to TNP in prior rate cases; rather, HL&P has consistently proposed rates to TNP based on a system unity rate of return. (Id., at 21-22.) He further noted that being a utility (with customers) itself, TNP should be charged no more than the system rate of return. (Id., at 22.)

On rebuttal Mr. Standish testified that Mr. Schuman's analysis fails to reflect the total change from the relative rates of return by class under current rates to those under the proposed rates. Mr. Standish explained that under current rates TNP's rate of return is 11.1058 percent or 31 percent greater than the system average rate of return. He noted that in this case HL&P proposes to reduce TNP's relative rate of return by 58 percent to 12.8548 percent which is 13 percent above the proposed average system rate of return. According to Mr. Standish this represents a significant reallocation of return among the rate classes and demonstrates HL&P's goal of attaining equitable rates of return between customer class. (HL&P Ex. 57 at 11-12.)

Mr. Standish further testified that the high rate of return under current rates results from the decrease in TNP's demand due to cogeneration; which jeopardizes HL&P's ability to meet operating revenue requirements and places the other ratepayers at risk of having to absorb the reduced revenue from TNP. According to Mr. Standish if TNP's rate of return is set at unity then HL&P's other ratepayers would be forced to bear the entire burden of TNP's load loss with no risk to TNP or its ratepayers. (Id., at 12.)

Mr. Standish testified that TNP is not being penalized for its use of cogeneration. He noted that Mr. Schuman's reference to testimony in Docket No. 5779 is out of context, and the point was and still is that HL&P's customers would benefit if TNP levelized its load without increasing the demands on HL&P's peak day. (Id., at 13.)

Mr. Standish also testified that the amount of TNP's future load reduction is not known and measurable. He testified that:

> The company in this docket based its estimates of TNP load on the last months of the test year. However, the company is not aware of future load reductions which indicates that future changes are not "known and measurable". In the case of Dow Chemical, the company received notice from the customer regarding load reductions such that the reductions were "known and measurable".

(Id.)

8. Staff

Mr. Rudolph testified that the assignment of a utility's base rate revenue requirement on an equalized rate of return basis is desirable only if it does not result in severe departures from existing revenue requirements. He noted that such is not recommended in this case because it would significantly alter the revenue requirements of several of HL&P's customer classes. (Staff Ex. 28 at 16.) Mr. Rudolph noted that based on the staff's revenue requirement recommendations the base rate revenue requirements increased substantially for the LGS, LOS-A, LOS-B, and SPL classes, while the GL class substantially decreased. Based on these factors Mr. Rudolph recommended the following revenue assignment guidelines:

1. An increase of approximately one-half the system average for Interruptible and Standby Service rate classes, and the Guard Lighting and Public Utility customer classes.

2. An increase of approximately one and one-half the system average for the Large General Service, Large Overhead Service-A, Large Overhead Service-B, and Street and Protective Lighting customer classes.

3. An approximately equal assignment of remaining dollars to the Residential and Miscellaneous General Service customer classes.

9. Examiners' Recommendation

[29] The examiners believe it is reasonable to seek to equalize class relative rates of return, but as pointed out by the staff, such can result in relatively large percentage increases to some classes. Precise increases which would result under the examiners' recommendations are not known at this time as the necessary calculations have yet to be made. However, for the most part, the examiners' modifications to HL&P's cost of service study are in line with those proposed by the staff. Accordingly, the examiners' recommend revenue requirement should be spread primarily based on HL&P's cost of service study as modified in Section XI. B.-H. above. To reduce potential adverse impacts the examiners recommend that the following limitations be imposed in this case. If a revenue increase is awarded, the examiners recommend that the base rate revenue distribution guidelines proposed by the staff and set forth in Section XI. I. 8. above be utilized in this case.

If a revenue decrease is awarded in this case, the examiners recommend that those classes which are currently not recovering their cost of service be maintained at the existing revenue level. The revenue reduction should be applied to move the remaining classes towards unity; however, no class should receive a decrease of more than one and one-half the system average decrease.