Company contends that exclusion of the indirect man-hours is inappropriate because the indirect labor performed by Westinghouse involved nonmanual man-hours that would have been necessary regardless of the number of direct labor man-hours expended.

In the Commission's opinion Staff's disallowance is appropriate with respect to both the Westinghouse direct and indirect man-hours. It has been established that nonmanual labor for Westinghouse was charged at an average of $53.26 in comparison to Daniel's charge of $14.25. Yet, Daniel was never back charged and costs were not excluded from Daniel's feeable base. Given the Company's failure to track Westinghouse's productivity and the magnitude of the overrun in the instrumentation area, it is appropriate to exclude unproductive Westinghouse man-hours as calculated by Staff.

k. Insulation Subcontract

Based on the findings and conclusions set forth above in Phase IV, I-C11 - Direct Labor Man-hours, Insulation, the Commission determines that it is appropriate to disallow man-hours associated with the excessive man-hours associated with the insulation subcontracts as calculated by Renken.

3. Adjustments Independent of Direct Labor Man-Hours

a. KG&E Administrative and General Expenses

Kansas Gas and Electric Company administrative and general (A&G) expenses are owner costs associated with the A&G expenses applicable to the construction of the Wolf Creek facility. Staff is proposing a disallowance of all A&G costs above what the Staff has approximated the Definitive Estimate to contain for those costs. This results in a $609,410 (total plant) disallowance.

The Staff believes it is impossible to ascertain which of those costs should be charged to the project and who should bear a particular cost, since KG&E and KCPL have not agreed upon a standard accounting manual to be used for Wolf Creek.

The Company counters Staff's arguments by pointing out that there is a draft accounting manual for Wolf Creek which cannot be put into final form until the Wolf Creek operating agreement is finalized. Company and KG&E have instead been utilizing the LaCygne Accounting Manual to determine how to charge the construction costs among the various owners. The Company asserts that those provisions in the LaCygne manual are substantially similar to those of the Wolf Creek draft manual. In conjunction with the use of that manual, KCPL requires all costs to be approved by KCPL's Director of Nuclear Operations and Vice President-SPO. KCPL further maintains it utilizes "written letters of understanding" which indicate which costs can properly be charged to the Wolf Creek project.

The Commission finds it is only reasonable to expect the Company to have a formalized accounting manual for the Wolf Creek project. It is imprudent to continue utilizing an accounting manual from another project which the Company's own auditors state is dissimilar enough from Wolf Creek that they were unable to determine the appropriateness of owner costs chargeable to the project.

The Commission finds that the Company had plenty of notice that an accounting manual was needed to fit the particular needs of Wolf Creek. As far back as KCPL's first audit report of Wolf Creek which pertained to the period June 1978 through December 1979, the Company was informed of various accounting inconsistencies regarding charges by the owners. As late as 1984, KCPL was informed by its auditors that certain A&G costs were not clearly defined and a formal agreement was necessary.

The Commission finds that the Staff's adjustment is reasonable. It is unnecessary to address the specific accounting inconsistencies which were set forth by Staff. The Commission finds its Staff cannot be expected to adequately and accurately audit costs where the Company's own auditors found it difficult to do so due to inefficiency on the part of Company's management to provide an appropriate accounting manual. Obviously, the "letters of understanding" were not sufficient to clarify the matter.

b. AWS Welds

Staff proposes to exclude from the recoverable portions of KCPL's Wolf Creek investment the costs associated with reinspections and remedial corrections of structural steel welds. Staff contends these costs would not have been incurred had Daniel adequately implemented project construction and documentation procedures and had KG&E detected or reported and corrected such discrepancies in a timely manner. Staff's adjustment reflects a $2,073,462 (total plant) downward adjustment of rate base.

Company witness Fouts testified the Company does not dispute Staff's position as it pertains to the breakdown of Daniel and KG&E Quality Assurance Programs, inadequate implementation of project construction and documentation procedures, and KG&E's failure to detect and report such discrepancies.

Since no conflict involving those issues apparently exists, the Commission finds Staff's disallowance is reasonable.

Additional testimony provided by Staff indicates that the above-described welding problems were a major factor in the delay of the NRC's issuance of the Wolf Creek operating license. According to Staff, the testimony pertaining to delay in licensing is not reflected in the above-mentioned $2,000,000 disallowance. Instead, it pertains to schedule impact and is nonquantifiable.

The pertinent facts, to which there is apparently no dispute, are as follows. The NRC informed KG&E in October 1984 that it required resolution of the AWS welding problems prior to issuance of a license to load fuel at Wolf Creek. On December 1, 1984, KG&E requested that the NRC issue the Wolf Creek operating license by December 31, 1984. KG&E maintained that all restraints to fuel load would be addressed in time to allow such issuance.

On December 31, 1984, KG&E submitted to the NRC its response to the NRC's "Violation Assessed Civil Penalty" which pertained to the structural steel welding problems. Therein, KG&E stated the safety-related structural steel welding problems would be resolved by January 15, 1985.

The problems were not corrected by that time. Additional information was still being submitted by KG&E in February and additional reinspections were being performed until March 1985. On March 4, 1985, results of 17 such reinspections were submitted to the NRC. On March 7, 1985, the NRC advised KG&E that the AWS welding matter was considered closed. On March 11, 1985, the NRC issued to KG&E a license to fuel-load.

The Company contends that the structural steel welding problem was only one of many "open items" which impacted the issuance date of the fuel-load license. Company enumerates many issues and activities which needed resolution prior to license issuance as of January 16, 1985. Company in particular makes reference to the fact that the NRC completed its review of the final Preoperational Test Package only one week prior to the NRC's announcement that the welding problem was considered resolved. The Company contends that any impact on schedule would have been, at most, less than one week.

The Commission has reviewed the items Company claims contributed to the schedule delay and finds that the structural steel welding problem was a major cause of more than two months delay in the issuance of the operating license by the NRC. This is not to say the welding problem was the only cause of the delay. However, it is undeniable that the NRC had informed KG&E that fuel-load could not take place until the AWS weld matter was resolved, and although license issuance was requested as early as December 31, 1984, it was not granted until two business days after the welding issue was closed.

c. Subcontracts/Direct Materials

Construction of the Wolf Creek cooling lake entailed a decision by the owners of whether to obtain rock products off-site or on-site. The Company determined it would be less expensive and less environmentally stressful to obtain the rock on-site. Although Sargent & Lundy (S&L), designers of the lake work project, had specification requirements for fine bedding gradation, the Company maintains it had indications from S&L that those requirements would be relaxed to allow its subcontractor, Clarkson Construction Company (Clarkson), to produce material on-site. The Company proceeded with production. Since no relaxation of the specifications was forthcoming, the Company had incurred additional costs and was forced to go off-site to purchase the fine bedding.

The Staff maintains that once it was apparent Clarkson could not meet the S&L requirements, Clarkson should have been required to go off-site to purchase fine bedding instead of being allowed to continue on-site production. Staff asserts the Company should not have proceeded with on-site production until receiving actual approval of the proposed relaxed specifications from S&L. Staff proposes to disallow $512,402 (total plant) for additional subcontractor costs and $2,237,757 (total plant) for associated direct materials cost.

The on-site quarry includes the Plattsmouth and Toronto ledges. A 1976 investigative report recommended against use of materials from the Plattsmouth ledge. In a second supplemental investigation performed in July 1977, the Commission was warned that an excessive amount of fines would result from use of the Toronto limestone on-site if it was crushed to the fine filter gradation specifications of S&L. An excessive amount of fines passing through the filter prevents, among other things, proper drainage. The report noted that fine filters would have to be imported from off-site. The report suggested that alternate gradations for fine filter and bedding could be submitted for approval. Guidelines for developing those alternative gradations were from S&L.

The contract was awarded to Clarkson based on a gradation other than that specified initially by S&L and allowed production through a dry process. Clarkson began work November 15, 1977.

Although the owners were aware of the problems involving on-site production, they proceeded on the basis that S&L could be persuaded to relax its gradation specifications, since S&L had relaxed some of its standards in the past. This belief by the Company was further reinforced by certain representations from S&L, which included a statement which rejected a proposed alternate gradation in order to give S&L more flexibility on alternate proposals once Clarkson began rock production, and the appearance that S&L was working with the owners and Clarkson to arrive at some solution short of holding firm to its specifications.

The Commission is of the opinion the Company did believe it could persuade S&L to modify its specifications. The issue is whether prudency dictated a firm commitment from S&L to that effect before proceeding with on-site rock production. The Commission finds that it did. No matter how convinced the owners were that S&L would "come around", it was imperative to have S&L's guarantee first. Instead, no relaxation of the specifications was forthcoming, additional money was expended for naught and the owners were eventually forced off-site to obtain fine bedding material. Therefore, the Commission is adopting Staff's proposed disallowance.

d. Unit 2

Unit 2 costs refer to those costs incurred in anticipation of construction of a second unit at the Wolf Creek site. Although the Wolf Creek site was chosen and developed with an eye toward accommodating a second unit, that unit was never actually planned.

In Re: Kansas City Power & Light Company, 24 Mo. P.S.C. (N.S.) 386, 408 (1981) (Iatan case), the Commission determined that facilities at a multiunit site fall into three categories:

(1) facilities that can only be used for the first unit and cannot be used and useful to subsequent units;

(2) facilities required for the first unit regardless of whether a subsequent unit is ever contemplated which did not require a

greater expense than if just one unit were contemplated, but are of such a nature as to support the use of subsequent units; and

(3) facilities that are necessary to the first unit, but were constructed to serve subsequent units at a cost greater than if just one unit were contemplated, and yet are cheaper than building separate facilities for each subsequent unit.

In this instance, Staff is proposing that a fourth category be adopted for facilities intended for use by units subsequent to the first unit which cannot be used or useful to the first unit. Staff refers to these costs as specifically identifiable facilities. Company considers them expansion costs. Neither Staff nor Company is proposing inclusion of those types of costs. All of the Company's expansion costs fall within Staff's definition. Staff also enumerates four other costs in its brief which it contends properly fall within its definition. Those areas relate to the circulating water system (CWS) and the essential systems water system (ESWS). They are: a section of CWS for piping installed under a railroad track; a section of CWS intake canal; CWS discharge pipes and ESWS discharge pipe stubs. It was necessary to install the piping under the railroad track now to avoid the necessity of tearing up the track at a later time. The underwater portions of the other items were constructed before the cooling lake was filled. Apparently the Company considers these costs as part of its common facilities proposal.

A majority of the Unit 2 costs fall within the third definition. Those costs generally relate to the cooling lake earthwork, CWS, ESWS and land that was inundated as a result of construction of a lake large enough to accommodate two plants.

The Company and Staff differ as to their quantification of the common facilities involving the cooling lake. Wolf Creek's cooling lake measures 5,000 acres. Only 2,500 acres was necessary for the existing unit. Staff made an independent estimate of the costs of a 2,500 acre lake. Staff's common facilities quantification is higher than Company's. Staff's calculations were based on a nonexpandable design, since it is Staff's contention Unit 2 cost is the amount by which the project is made more expensive by the provision for a second unit. The Company argues that it is improper not to consider the cost of an expandable 2,500 acre lake.

The Company is requesting the Commission to reconsider its decision in the Iatan case which excluded those costs from rate base which were incurred above and beyond what the facility would have cost had it been designed for only one unit. The Commission notes that decision reflects adoption of the Company's position in that case.

The Company maintains such costs are in the interests of the ratepayers, since additional costs would be required to construct the involved facilities in the future. The Company further maintains the decision to build such facilities was a prudent management decision.

It is clear that the Wolf Creek location was chosen, among other reasons, because it would accommodate two 1,100 MW units. This was evidenced by the 1973 Ebasco study, which evaluated potential Wolf Creek sites. Therefore, the Wolf Creek location is a multiunit site. The Commission finds that Staff's proposed fourth category should be added to the Commission's previous list of definitions for facilities at a multiunit site. Although no Unit 2 was planned, certain items were added to accommodate that unit if it was ever built. Those items are not necessary for the existing unit and are not "used and useful" at this time. They are essentially of no use at all unless and until an additional unit is built. Those items would fall within the fourth definition and include the four areas previously enumerated in Staff's proposal. The Commission finds those costs should not be put into rate base. They are of no value whatsoever to the current ratepayers. The costs associated with category three are the costs associated with designing the first unit to accommodate an additional unit. These costs include such things as oversizing pipes which are needed for the first unit and expanding the size of the unit cooling lake necessary for the first unit.

The Company has not persuaded the Commission to sway from its previous decision and the Company's previous position in the Iatan case. The Commission finds it is not in the current ratepayers' interests to charge them for costs above those necessary for construction of the existing unit. Since no second unit was ever actually planned, the Commission finds it was imprudent to incur additional costs which were apparently based upon nothing more than speculation and wishful thinking. If the plans for a second unit should ever come to fruition, those future ratepayers should pay for the benefits they receive from that plant: the current ratepayers should not be penalized.

The Commission determines that Staff's method of quantifying common facilities costs is more appropriate than the Company's and that the items enumerated herein should be disallowed, along with their associated indirect costs.

e. Daniel Fringe Benefits

In early 1974, the Wolf Creek owners received competitive bids from four companies seeking to provide construction services at Wolf Creek. The lowest bidder on the project, and the one chosen by the owners, was Daniel. Daniel's bid included a fringe benefit adder equal to 15 percent of the salaries of its nonmanual labor. That 15 percent could be adjusted to a maximum of 18 percent upon mutual agreement of the parties. The fringe benefit rate was below that of the other bidders.

In response to a 1975 KG&E request, Daniel, through Dean Drevitson, provided a detailed breakdown of the 15 percent fringe benafits package. Relying on that representation, the owners accepted the amount and signed the contract.

Staff proposes a $2,949,819 (total plant) disallowance of the costs associated with the 3 percent markup in fringe benefits based upon the owners' failure to obtain the supporting documentation necessary to justify the increase. Staff asserts neither the owners nor Staff could possibly determine the reasonableness of the expenditure without that documentation. Staff submits there is sufficient evidence to demonstrate the 15 percent rate should be disallowed.

The Company maintains that the original fringe benefit amount was never in question, only its separation into subparts. Company argues this disallowance is improper since it was not disallowed in the UE case. Company further argues that even at 18 percent, Daniel was low bidder on the project, hence no imprudency on the part of the owners was evidenced. Company asserts the increase was necessary to attract labor forces to the remote Wolf Creek construction site.

In 1977, Company requested an explanation for Daniel's requested fringe benefit increase at both Wolf Creek and Iatan. A letter which listed eleven categories and quantified increases in three of those areas was sent to the Company in May 1978. Company was not yet convinced of the need for the increase. In 1979, Daniel attempted to convince the Company by submitting auditors' reports, which simply stated that the costs of the retirement program had increased. Both the Company and its internal auditors maintained that inadequate justification for the increase existed. The Company's auditors suggested approval of the increase should be withheld.

In February 1981, the owners agreed to the increase provided Daniel could furnish a detailed breakdown of the proposed increase or a satisfactory certificate from its independent auditors in support of the increase. The owners received auditors' statements once again stating the costs of the retirement program had increased.

In April 1981, the contents of the original Drevitson letter were discredited by Daniel. Since the owners could not compare the requested fringe markup to the breakdown of the original 15 percent, KG&E determined in September 1981 that the only alternative left was an audit of Daniel's fringe benefit account by KG&E. Apparently this did not take place and the nonmanual fringe benefit increase was granted in November 1981, retroactive to April 1, 1981. At a later time the increase was approved for the general foremen.

The Commission disagrees with Staff's position that adequate evidence exists to disallow the original 15 percent fringe benefit amount. The owners relied in good faith upon the information submitted to them. They had no way of knowing their reliance was placed upon false or inaccurate data. The Commission finds it was reasonable for the Company to allow the original 15 percent fringe benefit.

However, once the Drevitson letter was discredited, there was no way to determine from the information given whether or not the 3 percent increase was reasonable or justified. Obviously, Daniel and the owners felt only 15 percent was necessary at the beginning of the project. Apparently, some changed circumstances existed to justify an increase. A flat statement to the effect that retirement benefits had increased was insufficient justification. A comparison of the original benefit areas to those areas exhibiting cost increases could not be made, not by the owners, the Staff, nor this Commission. Since there was no longer basic information broken down for the initial 15 percent fringe benefit rate, it was up to the Company to require Daniel to supply detailed information regarding the needed increase. That could only be performed by way of a detailed breakdown of both the original 15 percent and the supposed increases to that 15 percent.

It is irrelevant that the addition of the 3 percent markup still left Daniel the lowest bidder on the project. It was necessary to justify the cost increase. Prudent management dictates more control over costs than was exhibited by the Company in this instance. The Commission finds this to be particularly true since only one month earlier the owners were considering removal of Daniel as contractor due to low productivity. It is hard to imagine allowance of an increase in fringe benefits under such conditions with adequate supporting documentation; it is inconceivable without it.

With regard to the Company's argument that no such disallowances were proposed in the UE case, the Commission does not have sufficient evidence before it to determine whether or not the UE case involved similar circumstances.

f. Base Mat

Staff proposes a $3,019,074 (total plant) disallowance for the premium portion of overtime wages paid by the Company to recapture schedule delays which occurred as a result of the seven months hold on safety-related concrete. Staff maintains the work hold could have been avoided with adequate quality assurance programs when the base mat and reactor wall were poured and the base mat tested.

The Company claims that Staff has not demonstrated a nexus between the concrete placement problems and its proposed disallowance. The Company sets forth what it considers to be the appropriate test of that nexus. According to the Company, the Staff must show that "but for" the concrete placement problem, the schedule recovery program (SRP) would not have occurred and the $3 million in extra costs would not have been incurred. For example, Company submits that the winter of 1978-79 would have precluded some portion of the concrete work whether there had been a stop work order or not. The Company further claims that a credit offset should have been given Company for cost savings due to the overtime program. It is Company's assertion that Staff's use of the avoidance test is inappropriate.

The Wolf Creek construction project encountered numerous problems associated with the placement and testing of the concrete for the reactor building base mat. Further problems were encountered which involved voids occurring in the concrete wall of the reactor building. Those difficulties were major enough for NRC representatives to suggest further concrete work on the reactor building should be suspended pending quality assurance improvements, which included improved concrete placing and consolidation procedures, further training for concrete placing crews, upgrading of inspector and inspection proceedings and resolution of questions on base mat quality.

This was due to the NRC's belief that the owners' inquiry into the causes of those problems was insufficient.

KG&E stopped work on safety-related concrete in December 1978. Placement of safety-related concrete in structures other than the reactor building was resumed March 22, 1979. Safety-related concrete placement in the reactor building was not resumed until mid-July 1979, seven months after the stop work order was issued. The hold was removed when the NRC determined that the owners had taken appropriate actions to correct the weakness in their management controls and quality assurance program and when it had been sufficiently demonstrated that the base mat met design specifications. A Schedule Recovery Program (SRP) was instituted in August 1979 to recover the resulting schedule lag.

The Commission finds that Staff has developed a nexus between the base mat and reactor wall problem and the additional $3 million expenditures. The Wolf Creek SRP states in its introduction "[c]onstruction progress has been delayed as a result of the recent concrete hold. The options which are readily available to accelerate progress and place construction on schedule are presented within this report." The report further states that "[d]elay of the project is being caused by a lack of progress in concrete construction."

It is apparent that the stop work order was directly attributable to inefficient management controls over that portion of the project. The record is replete with documentation from the NRC which establishes weaknesses in the owners' management controls and quality assurance program. It is further apparent that the SRP was instituted as a direct result of the hold on safety-related concrete. Those findings, coupled with the Daniel quantification of the $3 million amount as being the cost of the recovery time component of the SRP, demonstrate that Staff's proposed disallowance is reasonable.

The Company's arguments that overtime would have occurred without the SRP and that a 3 percent overtime allowance was permitted under the Definitive Estimate are not persuasive. The amount disallowed was quantified as being attributable to the recovery time component of the SRP. It has been established that the SRP was a direct response to the hold on safety-related concrete. The Company's fears that additional overtime is being disallowed other than that resulting from the base mat and reactor wall problems is unfounded.

This is not a matter of avoidability: it is a matter of reasonable care. The determinative factor is that the overtime stems directly from management inefficiency and that inefficiency should not be rewarded in the manner of allowing those overtime costs into rate base. This is true even if the Definitive Estimate would otherwise have allowed a small portion to be recovered. The Commission determines the Company's argument that a hard winter would have prevented concrete work during some of the seven-month period is not backed up by specific data. The Company does not address the temperature on specific days or mention which or how many days would have been involved. The Commission dismisses that argument as unsubstantiated. The Commission believes that argument is a fallout of the Company's "but for" test for which the Commission finds no legal basis and is rejecting.

4. <u>Start-up and Preoperational Costs</u>

a. <u>Introduction</u>

The function of the Start-up Organization (Start-up) is to accept systems or subsystems from the construction organization for testing and confirmation of their operability. The term used to describe the handing over of such systems is "turnover". Once successful testing has been completed, the systems are then turned over to Plant Operations. The Start-up Organization at Wolf Creek was primarily staffed with outside consultants. Start-up - Preoperational costs increased from the 1977 Definitive Estimate level of $23,704,500 to $205,509,290 in actual expenditures as of March 31, 1985.

Staff proposes three separate adjustments to the Preoperational costs accounts totaling approximately $71 million. The adjustments include: $43,634,029 in Start-up Peaking costs; $10,538,900 in Precommercial Operations expense for Newport News Industries; and $17,057,074 in Preliminary Operations - Daniel Category 2.94 and Operations Support - Daniel Category 2.95. In addition, the Staff proposes a $6,529,037 disallowance for additional personnel which was hired to support the enhanced system turnover program and help correct quality documentation problems.

b. Excess Start-up Peaking Costs

Staff proposes to disallow the difference between the actual Start-up Peaking costs as of March 31, 1985, of $115,631,100 and Staff's allowable Start-up Peaking costs of $71,997,071. This results in a $43,634,029 disallowance of costs associated with outside consultants. Staff did not utilize the Definitive Estimate in determining its recommended level of start-up peaking man-hours because the Definitive Estimate was based upon use of permanent plant operating and maintenance personnel performing the majority of the testing, minimal use of contracted engineering assistance and heavy reliance upon vendor activities. Only 41,600 man-hours were allowed in the Definitive Estimate for Start-up Peaking.

Instead, Staff began by utilizing Revision Ten of the Start-up Organization's Staffing Schedule (Staffing Schedule) dated November 1981. The Staffing Schedule forecasted the need for 550,836 man-hours after December 1980, including a 10 percent overtime allowance, in addition to the 44,265 man-hours previously expended. Since no manpower curve was forecasted for I&C Technicians, Staff increased the forecasted man-hours by 48,620 man-hours to obtain its estimate of a reasonable start-up peaking forecast in 1981 of 643,671 man-hours.

A comparison was then made to the 1981 Callaway forecast for outside start-up consultants of 637,767 man-hours. The Callaway figure did not include man-hours for flushing and hydrostatic testing, which was not performed by Start-up at Callaway as it was at Wolf Creek. Staff therefore allowed additional man-hours above the Callaway forecast for: TMI modifications; additions to new subsystems;

additional testing required through licensing requirements; and updated estimation of man-hours to complete testing in the Reactor Building and Intake Structure. In addition, Staff allowed a 25 percent contingency and 96,890 man-hours for workers in various support capacities from January 1980 through December 1983. To arrive at that number, Staff utilized a 12.4 percent average overtime rate from January 1980 through October 1982 and a 32.1 percent average rate from November 1982 through December 1983. A 5 percent contingency was then added. Staff also allowed man-hours for several other activities that had been allowed at Callaway. As a result, Staff allowed 1,374,777 start-up peaking man-hours or $71,997,071.

In support of its proposed adjustment, Staff has set forth various reasons which it suggests contributed to Start-up Peaking costs in excess of the level determined by Staff as reasonable. The first reason identified by Staff is the uncoordinated construction completion effort at the project which was compounded by rework. That rework, according to Staff, resulted from inadequate, ineffective action by project management, SNUPPS changes in the interpretation of regulatory requirements and Bechtel design changes.

Successful integration of the Construction and Start-up schedules is necessary to project a reasonable fuel load date. That successful integration is contingent upon the status of construction completion. Staff contends the deficiencies in bulk quantity tracking affected the ability to plan manpower levels to meet a forecasted fuel load date and the accuracy of predictions of future unit rates, because Start-up was uncertain of the status of construction. The problem was exacerbated by an early shift from bulk quantity tracking to system emphasis. Staff points out that the owners were warned as early as 1980 that Daniel's tracking of installed materials was inaccurate.

The primary impact of rework was in the piping, piping hangers, HVAC and electrical commodities areas. The rework issue is addressed more fully under Section I.C.1., Direct Labor Man-hours. The SNUPPS changes in interpretation of regulatory requirements involved the SNUPPS design team's decision to attempt to get the NRC to change Regulatory Guide 1.29. The SNUPPS team never actually suggested the change to the NRC, and as a result the SNUPPS designs had to be modified to comply with the actual requirement. Dr. Hanauer maintains that any reanalysis or equipment change as a result of this modification was error and not related to regulatory change. According to Staff, the delays in the construction and completion effort were due to this rework of installed commodities and design changes which adversely impacted Start-up.

Staff's second reason involves ineffective and/or inadequate corrective action by management to perceived construction and turnover documentation problems which resulted in delayed system and subsystem turnovers to Start-up. Start-up was not receiving complete and accurate documentation of systems status when the systems were turned over to its control. The owners originally became aware of the documentation problem in late 1981. From 1982 on, the owners were reminded of the problems with turnover documentation. In fact, the NRC issued a Notice Of Violation And Proposed Imposition Of Civil Penalty relating to one system that was experiencing these documentation problems. The owners' attempts to address these problems took the form of task forces formed in 1982 and 1983. In February 1983 a stop work order was issued so that a System Turnover Quality Action Plan could be developed to correct the Daniel documentation problem and assure that Start-up received the accurate status of turnover systems. This prohibited turnover of safety-related systems from Construction to Start-up. When the stop work order was lifted in May 1983, Start-up testing was 61.4 percent complete versus a 72.5 percent projected completion. In other words, Start-up testing was three and three-quarters months behind schedule.

The Staff's third reason relates to the owners' decision to compress the Start-up Schedule. In May 1983 the projected fuel load date was accelerated from October 31, 1984, to August 15, 1984. The August date was based upon an already compressed Preoperational and Start-up test schedule due to documentation problems, construction delays and the stop work order. Start-up personnel increased from 240 people in July 1983 to 655 in May 1984. The personnel "increases were planned to accelerate Start-up progress which had fallen behind due to slow progress in component releases and system turnovers from Construction." The increase in personnel was accompanied by the freedom of Start-up to use overtime as needed. In December 1983, the owners implemented a 24-hour Preoperational testing schedule which required the use of overtime. As a result, overall productivity declined and increased manpower was needed.

The Company attacks Staff's quantification of allowable start-up peaking man-hours as being unsupported by this record and thus denying Company of its right to cross-examine. The Company argues that Staff's evidence of particular inefficiencies is not tied to specific cost or schedule effects. The Company asserts that the Staff's use of the Callaway figures is an invalid analysis since no comparison was made to determine whether such things as schedule and order of construction completion were similar at the two plants. The Company maintains that Staff's allowance for nonmanual overtime is inconsistent and that its ratio of nonmanual to manual personnel is unrealistic and unsupported. The Company suggests that since Staff witness Stinnett's testimony is tied to Staff witness Renken's findings, his conclusions are equally as flawed. Company faults Mr. Stinnett's quantification for not accounting for scope changes allowed by Mr. Renken or for adequate rework which the Company believes may not have been accounted for in the 25 percent contingency.

The Company reasons that there is no such thing as a trouble-free project and that it responded to the problems it encountered in an effective and timely fashion. It is Company's contention that it was primarily regulatory changes and not the reasons cited by Staff that increased its costs. Company presented industry comparison data to indicate that the overall duration from energization of the start-up transformer to fuel load was eight months less than the industry average.

Although the Commission has previously stated that the Definitive Estimate represents the best starting point in determining cost overruns, the Commission believes in this instance it was reasonable to begin with a later forecast which more accurately reflected the number and the type of man-hours needed for Start-up Peaking. The Staff's comparison of the 1981 Wolf Creek Start-up Forecast with that of Callaway is an appropriate method of determining whether the costs expended at Wolf Creek were reasonable, since the plants are substantially identical units. Staff's comparison revealed that the two forecasts were markedly similar. Yet, Staff determined that was not an adequate amount of forecasted hours for Start-up Peaking and added additional hours for various items discussed previously, including nonmanual flush and hydro personnel. The Commission believes the number of nonmanual Daniel direct and contract personnel in the flush and hydro group at Callaway was an appropriate number to utilize to increase the 1981 Wolf Creek forecast. The Commission does not believe the overtime percentages were applied inconsistently. In addition, Staff allowed a 25 percent contingency to cover necessary rework, regulatory lag, etc. There was no evidence by the Company that this 25 percent contingency was inadequate to cover the necessary rework.

The Commission finds Staff's method of determining a base line estimate fair and reasonable, particularly in light of the evidence that the start-up consultant's man-hours at Wolf Creek were not tracked to specific activities and that what evidence there was for the Start-up Peaking budgets at Wolf Creek was insufficiently detailed and inconsistently documented, unlike that of Callaway. The Company was not held to its Definitive Estimate, nor even to its 1981 forecast. Staff allowed additional man-hours which it attempted to project in the most accurate manner possible, by use of the man-hours allowed for an identical SNUPPS unit. It was up to the Company to present sufficient evidence of differences in schedule and order of construction completion between the two plants. That was not done.

The Commission has reviewed the parties' arguments and finds that Staff's explanations for the cost overruns provide a thorough understanding of the problems encountered by the Company in the construction of Wolf Creek. The Commission finds that the delays in construction completion due to rework as set forth by Mr. Renken in the Direct Labor Man-hours section, Section I.C.1. above, did carry over into the Start-up area.

The evidence indicated that there was a quantity tracking problem. It was demonstrated that an accurate projected fuel load date hinged upon forecast unit rates being achieved, manpower assigned to priority systems actually working those systems, and remaining quantities for each system being accurate. Without proper quantity tracking, those three requisites could not be met, an accurate projected fuel load date was impossible, and Start-up had no way of determining the actual status of the systems turned over to it. Although Company attempted to correct these problems, its actions were clearly ineffective for the most part as the same problems continued for several years.

The Commission recognizes that there were significant problems with system turnover documentation. Slightly over 5 percent progress was made in system turnovers from February through May 1983. The same was true from mid-May to mid-June 1983 for Preoperational testing. From mid-June through mid-September 1983 no progress was made in Preoperational testing. Although the Company argues that no substantial delay resulted due to the component release program, the evidence indicates that one of the Company's own consultants in December 1983 said increases in personnel were being made to accelerate Start-up, which had fallen behind due to the slow progress in component releases and system turnovers. Clearly, there was resulting delay.

The Company's basic argument is that increased regulatory requirements and changes are to blame for cost overruns. Yet the Company was unable to adequately quantify the cost of those additional requirements either in its testimony or in its reconciliation packages. Thus, Company would have the Commission allow all Start-up Peaking costs on this theory. Regarding industry comparisons, the Commission believes that they cannot be used to indicate management efficiency. Even if such were not the case, the Commission has nothing against which to compare the costs of that performance with other plants, nor any idea how the Company's actual, as opposed to projected, fuel load date would compare.

The Commission finds the delays resulting from an uncoordinated construction completion effort, coupled with significant documentation problems, appear to have contributed to delays in Start-up testing and eventually to schedule compression which resulted in additional man-hours, through additional personnel and overtime, as well as lower overall productivity. Although management attempted to alleviate some of the problems, its reactions were ineffective overall. This was obvious at the time and is not premised upon a hindsight analysis. Based upon the foregoing, the Commission is adopting Staff's recommended adjustment for excess Start-up costs.

c. Newport News Industries

Staff bases its disallowance of all costs incurred for Newport News Industries' preventative maintenance services upon Staff witness Renken. The preventative equipment maintenance at Wolf Creek was supplied by both Newport News Industries and Daniel. Daniel alone exceeded Staff's recommendation of allowable man-hours and Mr. Renken contends those man-hours should have been sufficient to do all of the maintenance work. Consequently, Staff recommends disallowance of all costs for the subcontractor, Newport News Industries.

Company contends that no disallowance should be made, as Daniel did pre-turnover maintenance and Newport News did only post-turnover maintenance. The

Company contends that UE was able to recover costs for both pre- and post-turnover maintenance.

The Commission believes the Company has been allowed a reasonable amount of man-hours for preventative equipment maintenance. Thus, the costs of Newport News Industries' preventative maintenance program will be disallowed.

d. Preliminary Operations - Daniel Cost Categories 2.94 and 2.95

Staff recommends a $17,057,054 disallowance associated with Daniel cost accounts 2.94 and 2.95. These accounts cover Daniel craft support of Start-up activities. Since Mr. Renken has included allowances for direct labor necessary to complete the plant and provide preliminary operations support, Staff contends it is unnecessary to allow these costs.

The Company argues that Mr. Renken has not properly accounted for all of these man-hours. Even if he did account for some of the man-hours in these cost categories, they would only reflect 20 percent of the total man-hours used. Company maintains that all of the man-hours should be allowed since they result from such things as delays and retestings due to TMI regulatory requirements, cold shutdowns, fire protection and security systems, which Staff does not refute.

The Commission has previously adopted the level of direct labor man-hours recommended by Mr. Renken. The Commission finds that Mr. Renken's analysis adequately accounted for increased regulatory requirements. The Commission does not put much credence in the Company's reconciliation package analysis. The reconciliation packages have been shown to be severely lacking, particularly in the area of adequate quantification of reasons for cost variances. See Section I.C.6., Project Cost Reconciliation. The Commission believes Mr. Renken's direct labor man-hours encompass a reasonable level of craft effort to provide preliminary operations support and to complete the plant. Therefore, the Commission is adopting Staff's recommended disallowance.

e. Additional Personnel

Staff recommends that $6,529,037 be disallowed for additional personnel which was hired to support the enhanced system turnover program and to help correct quality documentation problems.

The Company claims Staff's recommendation is not soundly based. It is a proposal to disallow the cost of all additional personnel brought on after mid-1983 to adequately staff the turnover effort. The Company contends increased Quality Assurance staffing was not needed until that time. It is the Company's further contention that if the Commission should want to disallow any of those man-hours, it should only be those related to inefficiencies, yet Staff proposes a disallowance of all personnel.

The Commission finds that additional personnel were needed as the number of systems being turned over increased. This would be true even if the Commission had not previously found there to be difficulties in the Start-up effort. Therefore, only a portion of those man-hours should be disallowed. Since the Commission has no way of determining what portion of the total man-hours is properly disallowed, the Commission is of the opinion the disallowance should be rejected.

5. Daniel Fee

Pursuant to the contract between the owners and Daniel, Daniel was to be paid a construction fee for their services in performing their scope of work for Wolf Creek construction. The fee was to be $4.5 million on a contract fee base of $600 million plus .75 percent of all dollars expended over the $600 million feeable base.

The as-built cost of the Daniel construction fee for the period ending March 30, 1985, was $8,487,095, excluding retention. The resultant $3,987,095 variance above the base $4.5 million fee was caused by actual increases to the fee base construction costs.

The Commission determines that the portion of the Daniel fee associated with the Daniel direct and indirect construction cost disallowances. which have been approved by the Commission should be excluded.

6. Project Cost Reconciliation

The Company's Management Performance Evaluation and industry comparisons have been previously discussed. This section pertains to the Company's reconciliation packages, the resulting Reconciliation Management Summary and the Staff's rebuttal and surrebuttal cases relating thereto.

In 1979, Staff began its construction audit of the Wolf Creek plant. In mid-1982, the owners determined that a cost reconciliation process was needed in order to adequately respond to Staff inquiries into the underlying reasons for various cost overruns above the Definitive Estimate. This resulted in the development of the Wolf Creek Reconciliation Group and numerous reconciliation packages.

The Reconciliation Group initially intended to coordinate reconciliation efforts with similar efforts at the Callaway plant and to reconcile quantity variances from each yearly project to the next, rather than from the Definitive Estimate to the most current forecast. The evidence indicated that the coordination of reconciliation efforts was unable to take place because Callaway's reconciliation effort was farther along than Wolf Creek's and in addition UE apparently believed its own reconciliation effort was superior to the effort at Wolf Creek. Mr. Renken testified that Callaway's reconciliation effort was superior to that of Wolf Creek in his opinion.

After instituting the original reconciliation, the owners discovered that the forecast-to-forecast reconciliation they had developed was not sufficiently answering Staff's questions. They subsequently abandoned that approach and utilized a reconciliation of cost changes from the Definitive Estimate to the 1983 forecast. This method resulted in the submission of 61 reconciliation packages to Staff.

Staff's evaluation of those reconciliation packages discovered a significant number of man-hours and dollars were left unreconciled or unexplained. After replacement of the Reconciliation Group's upper management with C.E. Linderman and C.L. Huston, in late 1983, the owners subsequently indicated to Staff in the spring of 1984 that new reconciliation packages would be issued which reconciled cost changes from the Definitive Estimate to the 1985 forecast. Those reconciliation packages were to supercede the previously submitted reconciliation packages. This substitution was performed over Staff's objection that its previous efforts would have been for naught. Staff requested that the Company instead correct the deficiencies of the previously submitted reconciliation packages and only reconcile the variance from the 1983 to the 1985 forecast. Company denied Staff's request.

The Definitive Estimate to 1985 reconciliation packages were revised substantially, in many cases adding new reconciling items while deleting previous ones entirely. The reconciliation packages were further updated in Mr. Linderman's rebuttal testimony, where additional reconciling items were once again added. Staff was apparently not informed of the updated information until that filing.

Staff's evaluation of the reconciliation packages demonstrated that many of them relied extensively on estimating techniques, including order of magnitude estimates and plugged numbers, as well as unquantified explanations and various other support which was unverifiable. Order of magnitude estimates are approximate estimates made without detailed engineering data and, according to Mr. Linderman, range in accuracy from +60 percent to -40 percent. Plugged numbers represent those instances where a number of explanations are presented to explain a portion of a reconciling item variance. The remaining unreconciled dollars are then assigned, or plugged in, to the variance explanation that remains. Unquantified explanations refer to those instances where two or more reasons are provided for a reconciling variance.

Staff set forth various recommendations in this case. Staff's direct case consists of both independent and discrete analyses. An independent analysis involves an entire cost area. A discrete analysis involves an evaluation of only a portion of a cost area. Those proposed disallowances are based upon allegations of management imprudence by the Staff. Staff's rebuttal case consists of an in-depth examination by OKA of approximately one-third of the reconciliation packages supplied by the Company. OKA analyzed the extent to which quantifications presented in the reconciliation packages were capable of being verified; in other words, where there was sufficient information presented to allow a determination of reasonableness. Staff's surrebuttal case attempted to assess the reasonableness, quality and amount of documentation which supported the variance explanations and quantifications. Staff's proposed disallowances relate to those areas where insufficient documentation and quantification existed to allow Staff the ability to determine the reasonableness of the variance explanations.

Clearly, the Company did not have a system in place which allowed it to track the causes of various overruns contemporaneously with their occurrence. The variations in the formats of the reconciliation packages demonstrate there was no consistent and reliable basis upon which Staff could conduct an audit. Complete and accurate information was necessary in the reconciliation packages, since the owners were providing answers through the reconciliation packages to questions which developed during Staff's independent audit.

Although the Commission agrees with Company's assertion that it may not be possible to assign reasons for overruns with absolute precision, the Commission believes that a system could have been and should have been implemented which at least attempted to classify the reasons for the overruns at the time they were incurred. After-the-fact estimates with wide-ranging accuracy, plugged numbers and pages of unquantified explanations constitute insufficient information from which a determination of reasonableness can be made. This is true in spite of Mr. Linderman's assertions to the contrary. The Commission finds that Mr. Linderman's testimony was often evasive and unresponsive, therefore, the Commission is unable to rely upon his testimony.

The Commission finds the reconciliation packages were further deficient, as they did not properly assess the extent to which cost overruns were attributable to problems over which management had control. Thus, Company would have the Commission believe that all cost overruns were wisely and prudently incurred.

Although the Commission agrees with Staff's underlying analysis which demonstrates the deficiencies in the reconciliation packages, the Commission cannot accept Staff's proposed disallowances in its rebuttal and surrebuttal cases due to the fact that the presentation of those cases was somewhat inconsistent and difficult to relate to the direct case. The figures in the rebuttal and surrebuttal cases are, at times, vastly divergent. The Commission believes it is inappropriate to simply choose the lesser of the two. One of the evaluations should reflect the actual amount of cost overruns which are not supportable. The Commission finds the use of the discrete versus independent evaluations somewhat suspect in this instance, since the Staff did not delineate the categories of all of its evaluations until requested to do so by the Commission at the end of the hearing. That delineation was filed as a portion of Late-filed Exhibit 604.

For the foregoing reasons, the Commission is rejecting Staff's proposed disallowances in its rebuttal and surrebuttal cases as they pertain to the reconciliation packages. The Commission determines that the Objection Of Kansas City Power & Light Company To Admission Of Staff's Late-Filed Exhibit 604 is moot, since the Commission is not relying upon that exhibit nor its differentiation between discrete and independent evaluations for its findings. The Company's Motion To Strike February 14, 1986, Update Of Staff's Case involves the updated versions of Exhibit 392 and Appendix A to the Hearing Memorandum. That version of Exhibit 392 is not being relied upon by the Commission and Appendix A simply updates the issues originally designated in the Hearing Memorandum. Therefore, the Commission determines the Company's motion is also moot.

D. Public Counsel's Position

1. Prudence Adjustment

Public Counsel contends that KCPL failed to conduct an adequate review of its decision to continue to build Wolf Creek between the years 1977 and 1982. Public Counsel maintains that this failure to reevaluate the decision to continue the construction program was imprudent and recommends an adjustment where the alleged losses associated with not having cancelled Wolf Creek are excluded from rate base.

Public Counsel's prudency adjustment focuses on the Company's generation planning during the period subsequent to the NRC licensing hearings, 1976 through 1982.

Construction estimates for Wolf Creek prepared by the owners nearly doubled from April of 1973 through December of 1976. However, the definitive estimate included no recognition of the existing cost escalation trends. In the industry, nuclear O&M costs rose 37 percent per year during the years 1977 through 1981. Capital additions for nuclear plants increased 31 percent per year during the same period. In March, 1979, the Three Mile Island accident occurred causing grave concerns about the future of nuclear power.

In early 1979 and 1980, the construction engineer and project manager were questioning the accuracy of the project's cost forecasts. In 1981, the Company's construction manager recognized that the project was slipping six to eight months per year and that the budget was increasing $200 to $300 million per year. The project manager stated that he had little confidence in a 1983 commercial operation date or that the plant could be completed for $2 billion.

In April, 1981, KCPL's energy supply coordinating committee determined that peaking capacity was needed. The committee indicated peaking capacity should equal

22 to 23 percent of its load. At that time the Company's peaking capacity was 17.5 percent of its 1981 peak load.

In light of the above considerations, Public Counsel argues that prudent utility management would have evaluated the continuation of Wolf Creek by performing a study comparing alternative generation options. Public Counsel's evidence shows that between 1977 and 1982, KCPL did not perform any significant studies evaluating the merits of continuing the project as opposed to pursuing alternatives.

The Company did perform some cancellation cost analyses but no analysis was made to determine the cost of an alternative generation plan. Company witness Doyle, KCPL's president, Chief Executive Officer and Chairman of the Board, cited certain 1980 studies performed by Ebasco Services, Incorporated, Dr. James F. Hanley and Cresap, McCormick and Paget, Inc., respectively. None of the three studies compared Wolf Creek construction cost to an alternative plan.

Company witness McPhee mentioned a 1980 study performed by Company witness Evans for Kansas Electric Power Corporation comparing the Iatan generating unit and the Wolf Creek generating unit. The evidence reflects that this study was not relied upon for planning purposes.

In 1980, the Company engaged Decision Focus, Inc., for a generation planning study. However, the study assumed Wolf Creek on line in 1984. In response to the Commission's order in Case No. EO-81-101, directing the Company to perform a generation expansion study, the Company filed KCPLAN 81, which also assumed Wolf Creek.

Public Counsel's witness Rosen analyzed coal versus nuclear studies performed by KG&E. KG&E performed nuclear versus coal studies in 1973 and 1975, which found an advantage for nuclear power. The 1975 study found a levelized annual cost of $83.65 million per year for nuclear and $87.79 million for coal. KG&E performed three subsequent studies in bar graph form and in 1980 Ebasco Services, Incorporated reviewed the five previous nuclear versus coal studies, but performed little independent research and no new economic analysis.

KG&E prepared a 1981 three-page study comparing Jeffrey 3 coal unit, Wolf Creek and two reference coal units favoring the nuclear option. Although this study appears to overstate coal O&M and understate nuclear O&M it is unknown whether KCPL relied on this study.

Rosen testified that none of the above-referenced studies amount to a state of the art reassessment of nuclear versus coal based on the emerging knowledge of the relative cost trends of each generating option.

Rosen performed a retrospective analysis taken from data available in 1981. The 1981 time frame was chosen for the following reasons: (1) the Three Mile Island effects were known; (2) the industry literature contained many of the cost trends which had emerged by that time; and (3) restrictions on gas consumption and gas-fired boilers had been rescinded.

Rosen's retrospective study assumes: (1) $2.279 billion capital cost for Wolf Creek based on data available at the time. This compares to the owners estimate of $1.95 billion at the time; (2) actual O&M expenses for nuclear plants through 1980 assuming growth at two percent above inflation through 1998 and at the rate of inflation thereafter; (3) capital additions based on the cost of total additions through 1980 adjusted for estimated growth rates; (4) nuclear fuel costs based on KCPL's 1982 forecast; and (5) decommissioning costs of $101 million.

The retrospective analysis assumes a 436 megawatt coal plant in 1992 to replace KCPL's share of Wolf Creek at a cost of $1.072 million. It also assumes 300 megawatts of combustion turbines in the 1980's. The analysis assumes a 74.3 percent capacity factor for the coal plant and approximately 60 percent capacity factor for Wolf Creek. Prior to the 1992 coal plant, the analysis assumes a fuel mix of 92 percent coal, 2 percent oil and 6 percent purchased energy.

Based on the retrospective analysis, Rosen concludes that even assuming 100 percent recovery of and the full return on sunk costs over 30 years, the completion of Wolf Creek represents a cumulative net loss to the ratepayers of almost $140 million as compared to abandonment of the project and construction of 300 megawatts of combustion turbines during the1980s along with the 436 megawatts of base load coal in 1992. Assuming 100 percent return of but no return on the sunk investment over a ten-year period, results in $641 million cost to the ratepayers for completion versus cancellation.

Based on the retrospective analysis, Public Counsel proposes that a penalty should to be assessed against KCPL for failure to cancel. Rosen proposes the denial of Wolf Creek losses which were incurred subsequent to 1981. Rosen calculates this cost at $897 million by subtracting abandonment costs of $969 million from the Rosen calculated losses associated with Wolf Creek which are discussed in Section II below, Economic Excess Capacity.

Company witness Doyle testified that although KCPL was aware of escalating costs, schedule trends and diminished load growth, the Company took the view that cancellation was not in the best interest of the customers because of uncertainties regarding natural gas, foreign oil supplies and increasing coal costs.

The Company's 1975 generation expansion study was admitted into evidence as Exhibit 512. That study examined 24-year cumulative differences in costs for seven generation plans assuming high and low escalation rates. Under the high escalation rate scenario the plan assuming 412 megawatts of Iatan in 1980 and 475 megawatts of Wolf Creek in 1982 was the sixth most expensive plan. The most expensive plan assumed the cancellation of the 1980 Iatan plant and Wolf Creek as a fossil unit installed in 1982. The least expensive plan was a cancelled 1980 Iatan coal plant and 575 megawatts of Wolf Creek as a nuclear plant in 1982. The second most cost effective plan was no Iatan or Wolf Creek unit. Under the scenarios assuming lower escalation rates, 420 megawatts of Iatan in 1980 and 475 megawatts of Wolf Creek in

1982 was the most expensive plan. The least expensive plan assumed no 1980 Iatan unit and no Wolf Creek nuclear unit.

In Re: Kansas City Power & Light Company, 23 Mo. P.S.C. (N.S.) 474, this Company was found by the Commission to have excess capacity and the Commission criticized the Company for ignoring the above-described 1975 generation planning study.

In light of the above, the Commission agrees with Public Counsel that prudence would have dictated a careful evaluation of whether the Wolf Creek plant should have been cancelled. The Company's 1975 generation study should have raised questions as to whether the Company was planning excessive base load capacity. The Company should have reevaluated its generation plan on an ongoing basis. Nevertheless, the Commission is unable to find that the Company should have cancelled the plant in 1981 based on Public Counsel's retrospective analysis. At that time the Company had expended approximately $510 million for its share of the Wolf Creek plant. It has been shown that capital additions were not included in Rosen's studies until 1983 and in addition, the Commission is of the opinion that Rosen's capacity factor for Wolf Creek is understated thereby overstating the Wolf Creek associated loss that would be calculated under such a study. Therefore, the Commission is not convinced that if Company had performed a generation expansion study it would have concluded that the plant should be cancelled. Accordingly, the Commission determines that Public Counsel's prudence adjustment should be rejected.

2. Economic Excess Capacity

Public Counsel maintains that Wolf Creek represents a loss over its lifetime and thus will provide no economic benefits to ratepayers. Public Counsel contends that because of the alleged losses, economic excess capacity exists on KCPL's system. Based upon traditional "used and useful" theories utilized in traditional excess capacity adjustments, Public Counsel recommends that the Commission share the risks associated with the alleged economic excess capacity between shareholders and ratepayers. To accomplish a sharing, Public Counsel proposes that the amount of the losses associated with Wolf Creek be excluded from rate base while allowing full recovery of depreciation and taxes associated with the Wolf Creek investment.

Public Counsel witness Rosen testified that rising capital costs, rising O&M costs and Wolf Creek being the wrong type of capacity for KCPL's system needs has contributed to the economic excess capacity.

In order to determine whether Wolf Creek represents economic excess capacity, Rosen performed a cost benefit analysis of the effect of Wolf Creek over a 30 year lifetime compared with the cost of meeting the system load without Wolf Creek. The analysis is based on measuring the annual required revenues for the Company assuming Wolf Creek in-service and operating in one case and assuming that Wolf Creek had never been built in a hypothetical alternative case ("Wolf Creek in" and "Wolf Creek out" cases). Rosen's analysis measures the difference between the two required revenues streams on an annual and cumulative present value basis.

Rosen's analysis, designated his "reference case" under the "Wolf Creek in" scenario, assumed capital costs of $2.90 billion and an October 1, 1985, in-service date. The analysis assumes 1986 O&M costs at $76 million increased over 30 years at one percent above inflation which is a real growth rate of 2.5 percent. The study assumes first year capital additions of $45 million assumed to increase at an average escalation rate over the first 25 years at 1.5 percent above inflation. This estimate is based upon a study of nuclear plants for the years 1970 through 1983. The "Wolf Creek in" case assumes a 56.2 percent annual average capacity factor over the life of the plant.

Rosen's "Wolf Creek out" case assumes a 15 percent reserve margin, capacity purchases of 100 megawatts for 1984 and 1985, capacity purchases of 200 megawatts for 1986-1987. The Wolf Creek out case assumes 200 megawatts of combustion turbines added in 1988, 100 megawatts of combustion turbines added in 1989 and a 265 megawatt coal unit added in the year 2000.

Based on the analysis, Rosen concludes that the cumulative net present value impact of Wolf Creek on the ratepayers will be a loss of $1.87 billion over 30 years. Eighty-three percent of the $1.87 billion in losses occurs in the first 10 years of the plant's operation and 61 percent of the losses occurs in the first five years.

Rosen performed sensitivity analyses to his "reference case" study as follows: (1) the "KCC case" assumes Company's load forecast in lieu of Rosen's ESRG load forecast; (2) the "Company case" uses Company assumptions with respect to replacement power costs, nuclear O&M and capital additions; (3) "PSC case" assumes a 39.5 book life for depreciation, the Company's decommissioning calculation, the Company case replacement energy and capacity costs and 1984 O&M costs at $61.2 million escalated at six percent, capital additions at 1.9 percent and a 60 percent capacity factor.

Rosen's "KCC case" results in a $1.80 billion loss over the 30 year life of the plant. The "Company case" results in a $1.69 billion loss over the 30 year life of the plant. The "PSC case" results in a $1.75 billion loss over the same period.

Company witness Fitzpatrick in rebuttal to Rosen's testimony, performed a "Wolf Creek in" versus "Wolf Creek out" analysis similar to that of Rosen's which resulted in a benefit of $41 million in contrast to to Rosen's $1.8 million loss.

Fitzpatrick's analysis assumes lower capital additions costs, lower O&M costs, lower decommissioning costs and a 61 percent capacity factor for the Wolf Creek in case. Fitzpatrick's "Wolf Creek out" case includes a 22 percent rather than a 15 percent reserve margin. Fitzpatrick's analysis assumes the Company's load forecast, differing assumptions regarding the amount and availability of economy purchases and sunk costs of $970.2 million as calculated by Rosen in his retrospective analysis. Fitzpatrick's "Wolf Creek out" case assumes a 165 megawatt coal unit in 1986, 100 megawatts of combustion turbines in 1986, 100 megawatts of combustion turbines in 1989 and a 265 megawatt coal unit in 1990.

Fitzpatrick's analysis does not replicate Rosen's analysis as it is purported to do. Rosen's "Wolf Creek out" case assumes Wolf Creek had never been built. Thus, any alternate plan substituting for Wolf Creek must commence in 1985, when the prospective analysis commences. It is, therefore, improper to include Wolf Creek sunk costs since the analysis assumes that Wolf Creek was never built. In addition, Fitzpatrick's analysis improperly assumes the addition of two coal plants before it is possible to build them. The effect of including the additional coal plants and sunk costs decreases the total cost of the Wolf Creek out case by $969 million for the sunk costs and $400 million for the coal plant. Thus, if all of Fitzpatrick's assumptions are appropriate except for the inclusion of the coal plant and the sunk costs in the "Wolf Creek out" case, Mr. Fitzpatrick's analysis would show a net loss of $1.3 billion associated with Wolf Creek.

In Re: Union Electric Company. 27 Mo. P.S.C. (N.S.) 183 (1985), Rosen, on behalf of the Public Counsel, presented the Commission with a study of the economics of the Callaway plant. The study utilized the same concepts and approach as the Rosen prospective analysis presented herein. In the UE case the Commission rejected the Public Counsel's approach on the following ground:

> In the Commission's opinion, 30-year projections are speculative even if the underlying assumptions are well reasoned. In this case, the Commission has accepted assumptions related to O&M costs and decommissioning costs which are not consistent with Dr. Rosen's assumptions. Upon the evidence herein, the Commission is unable to find that the Callaway Nuclear Plant presents a $3 billion loss. 27 Mo. P.S.C. (N.S.) 183, 250

The Company's study adjusted for the coal plants and sunk costs shows a substantial loss. However, even under the Company's study the loss would be less than the $1.3 billion if the study assumed a 76 percent lifetime capacity factor which is consistent with the findings herein . Fitzpatrick testified that the difference in a 56.2 percent and 61 percent capacity factor could amount to a difference of $33 million if Wolf Creek is assumed to replace coal generation and $95 million if Wolf Creek replaces purchases. Thus, a capacity factor of 76 percent which could be equivalent to the availability found reasonable herein, would substantially reduce the losses associated with Wolf Creek.

Public Counsel has established that the majority of any losses associated with Wolf Creek will be experienced in the first 10 years of operation. Under his reference case scenario 61 percent of the calculated losses occur in the first five years and 83 percent occur in the first 10 years. Based on the analysis and studies presented to the Commission regarding the economics of Wolf Creek, the Commission concludes that at least in the foreseeable future, Wolf Creek has the potential to represent a loss when compared to alternative expansion plans. However, the Commission still believes that 30-year projections, although appropriate for planning purposes, are speculative for purposes of calculating permanent rate base exclusions. Therefore, the Commission must reject Public Counsel's economic excess capacity proposal.

E. Miscellaneous Rate Base Proposals

1. Depreciation Reserve and Deferred Tax Reserve Offset To Rate Base

Staff proposes to increase the Wolf Creek depreciation reserve offset to rate base by one-half of the first year Wolf Creek depreciation. Like Staff, DOE increases the depreciation reserve offset to rate base and, in addition, increases the deferred tax reserve offset to rate base by one-half of the first year deferred taxes.

The purpose of these adjustments is to recognize an average first year Wolf Creek investment. Although the Company agrees that it is appropriate to recognize an average rate base and that the Wolf Creek rate base will decline, it opposes the adjustments since capital additions are not included and since the Wolf Creek investment is calculated as of March 31, 1985.

The Commission determines that the Company's argument should be rejected. The inclusion of capital additions would violate Section 393.135, RSMo 1978. The March 31, 1985, cutoff date for Staff's audit, determines the Wolf Creek investment in this case and is not relevant to arguments related to the appropriateness of using an average first year Wolf Creek rate base. In the Commission's opinion it is appropriate to use an average Wolf Creek rate base in recognition of the declining Wolf Creek rate base. Accordingly, Staff's and DOE's positions regarding the depreciation reserve and deferred tax reserve offset to rate base are adopted.

2. Deferred Tax Reserve Related To Excluded Investment

The Company and Staff propose that any deferred taxes associated with excluded Wolf Creek investment should not be included in the deferred tax reserve which is deducted from rate base and amortized to the income statement. The Public Counsel opposes any reduction of deferred tax reserves associated with excluded plant.

The deferred tax reserves in question are associated with prior Commission decisions relating to normalization of tax savings. Public Counsel argues that normalization was allowed in prior cases because of the Company's weak cash flow and, thus, the Commission determined that the tax savings at issue were to be flowed through to ratepayers over a number of years rather than in the year they were incurred. Therefore, the Company's cash flow position is the only reason that tax flow savings were not flowed through in prior years. Based upon this argument, the Public Counsel argues that the tax savings should now be flowed through to the ratepayers.

The Company argues that if ratepayers do not pay for a portion of Wolf Creek investment, then the tax savings should flow to the investors.

Having considered Public Counsel's and the Company's arguments, the Commission determines that the tax benefit should flow to the one who pays for the investment which gave rise to the deferral. Had the tax benefits been flowed through in prior cases, the assumption would have been that the investment would be included in rate base at some future date. Since the AFUDC interest component which gave rise to the tax savings will not be charged to the ratepayer, the ratepayers should not receive the benefit of the tax savings. Therefore, the Commission determines that the deferred tax reserves associated with any excluded plant shall not be used to offset rate base and subsequently amortized to the income statement.

3. Long-Range Operating Study

With the addition of the Wolf Creek generating unit, minimum load problems will exist on the Company's system. All generating units have a minimum load below which they cannot continue to operate because of equipment limitations. An average minimum load tends to be about 25 percent of full output. A low load factor, needle peaking system such as KCPL's, has a hard time matching load and generation. Day to night variations in load presents a problem of meeting the peak load during the day and meeting the minimum load requirement at night. The problem is not solved by taking units off at night because significant maintenance cost penalties would be incurred.

KCPL is attempting to address minimum load concerns by changing the way it operates its units and by selling power. The Company's March, 1984, long-range operating study recommends the following actions: (1) LaCygne No 1 would be operated seasonally May through September but unavailable during the balance of the year; (2) Hawthorn 5 would be operated seasonally from May through September, but available during the balance of the year with a few days notice to cover major unit outages; (3) one Montrose unit would be deactivated; (4) one Montrose unit would remain on line and the other would be on standby to meet load upon a few hours notice; (5) Grand Avenue facility would be retired from electric service; and (6) reserve shutdown of Hawthorn Units 1 through 4 would continue.

The Company's operating plan was updated in September of 1985. The Company cites the improved coal contract for Hawthorn Unit No. 5, increased interchange sales and a 75 megawatt long-term capacity sale to the City of Independence, Missouri, as the reason for the update. Under the updated plan, the Company alters the previous plan as follows: (1) LaCygne 1 would be available seven months of the year instead of five months; (2) Hawthorn 5 would be available all months of the year instead of five months; and (3) Montrose 2 would be activated. The Company has assumed that Wolf Creek will be operated at 70 percent on the weekends, although it may be operated as low as 50 percent power if the owners would agree to such a mode of operation.

The Public Counsel raises the concern that because of the Company's operating plan ratepayers are paying for units that are not being fully utilized. Public Counsel states that it would be proper for the Commission to reduce revenues associated with units which are not being utilized or are being under utilized.

Public Counsel also raises the question of cross subsidies associated with power sales. The Company is selling power at the incremental fuel cost plus a 10 percent markup. Public Counsel states that Wolf Creek incremental fuel costs are .7 cents per kwh. However, fully embedded costs per kwh have been estimated at 13 cents per kwh in its first year and 9 cents per kwh levelized over thirty years.

Public Counsel points to the sale to Independence, Missouri as an illustration of a possible ratepayer subsidy. Although the Company contends that the Independence sale allows Montrose 2 to remain active, Montrose 2 will not necessarily be used to provide power to Independence. Montrose 2 may be shutdown much of the year and power to Independence provided from other sources. Thus, the sale is more akin to a system participation sale than a unit participation sale, even though the price is tied to one unit.

The Commission believes that the concerns raised by the Public Counsel with regard to the minimum load problems should be monitored and addressed. The Commission finds that the Company shall file an updated operating plan, showing the actual operation of its units for the first 12 months after Wolf Creek is in service and the Company's operating plan for the succeeding 12 months. The Company shall also maintain electronic dispatchers' logs so that the Company's interchange activities can be monitored.

II. Excess Capacity

A. Accredited Capacity

Staff contends that the need for Wolf Creek arises only because of the Company's derating and retirements of its fossil plants. In addition, Staff maintains the deratings and retirements of Company's fossil plants are due to improper operation and maintenance of Company's fossil plants.

Company contends that prior to 1978 it substantially overstated its accredited capacity reported to the MoKan power pool. Company maintains that the deratings and retirements of its fossil plants are caused by obsolescence, premature aging or economic reasons.

Staff witness Miliaras proposed four sets of accredited ratings as follows: (1) near term base, 2773 megawatts; (2) near term peak, 2886 megawatts; (3) future base, 2991 megawatts; and (4) future peak, 3093 megawatts.

Base ratings are for the day-to-day dispatch and production cost modeling of the system. Peak ratings refer to the maximum capability KCPL's plants can reliably deliver if properly maintained and operated. A peak rating does not necessarily imply the maximum possible output of a unit, but the use of a unit to provide generation for the peaking range for the Company's load duration curve.

Near term ratings refer to the base and peak ratings of Hawthorn units 1 through 4, used for natural gas fired summer peaking and the remaining KCPL fossil-fired units in their current condition of repair and maintenance. Future ratings refer to what base and peak ratings would be if KCPL's older plants are rehabilitated to near their full potential and are maintained and operated properly. A comparison of KCPL's ratings showing installed capacity, 1973 and 1974 accreditations, 1984 accreditations, and Staff's proposed near term and future accreditations are set forth in the chart below:

NET CAPABILITIES OF KCPL
FOSSIL-FIRED POWER PLANTS MW

	Installed Capacity	1973-74 MOKAN Accred.	1984 MOKAN Accred.	Proposed Near Term Accred. Base	Proposed Near Term Accred. Peak	Proposed Future Accred. Base	Proposed Future Accred. Peak
Hawthorn 1	75	75	0	65	65	75	75+
2	78	78	0	65	65	78	78+
3	119	119	0	85	85	119	119+
4	133	133	0	85	85	133	133
H 1-4 Total	405	405	0	300	300	405	405+
Montrose 1	185	185	150	159	159	180	180+
2	182	182	150	162	162	180	180+
3	192	193	160	170	170	190	190+
M 1-3 Total	559	560	460	491	491	550	550+
Hawthorn 5	520	520	450	458	500	500	520
LaCygne 1	412	---	343	343	354	343+	354+
LaCygne 2	315	---	315	315	325	315	325
Iatan	469	---	469	469	472	469	483
NE CTs 11 & 12	101	101	85	83	97	91	104.8
13 & 14	116	---	95	104.6	115.8	104.6	115.8
15 & 16	116	---	95	104.6	115.8	104.6	115.8
17 & 18	116	---	95	104.6	115.8	108.6	119.8
Total CTs	449	101	370	397	444.4	409	456.2
Total MO	3129		2407	2773	2886	2991	3093+

Staff proposes future base ratings for the purpose of determining the need for Wolf Creek in its phase-in model and for purposes of determining KCPL's required reserve margin. Company proposes the 1984 MoKan accreditation.

As can be seen from the chart set out above, Company and Staff are in disagreement as to the proper accreditation for the following units: Hawthorn 1 - 4, Montrose 1 - 3, Hawthorn 5 and the Northeast Combustion Turbines.

1. Hawthorn 1 - 4

Hawthorn units 3 and 4 were last operated in September of 1982 and were placed on inactive reserve in June of 1983. The units are unable to meet the City of Kansas City's air pollution standards as the scrubbers need to be replaced at an estimated cost of $25 million.

Hawthorn 1 and 2 were last operated in January of 1984 and were placed on inactive reserve in June of 1984.

The Company's practice of cycling the Hawthorn units to address minimum load problems has contributed to aging and premature deterioration of the Hawthorn plants. Cycling has caused material creep, and low cycle fatigue manifested in the form of turbine shell cracks, rotor cracks, generator rotor and boiler tube failures. These units were designed for minimum start-ups and shutdowns.

Company intends to rehabilitate the units in the 1990s at an estimated cost of $110 to $120 million. In the near term the units could be operated on natural gas for summer peaking at an estimated cost of $12.9 million and $5.5 million in annual O&M costs.

The Hawthorn 1 - 4 units are designed for a minimum of start-ups and shutdowns and are not designed for cyclic duty. In the 1950s and 1960s, the consequences of cycling duty were known. The Company admits that cycling is disastrous unless the unit is specifically designed for it. The Company also admits that early modifications of the units for cycling could have extended their lives.

In 1978 General Electric performed a test of Hawthorn 1's rotor and recommended reinspection within three years because of possible rotor problems. The next test was not performed until 1984.

As a result of a ground that developed in the Hawthorn Unit 4 rotor field in December 1979, Westinghouse made a temporary repair and recommended that KCPL not run the unit more than 14 months before rebuilding or replacing the generator rotor. KCPL did not follow Westinghouse's recommendation.

The evidence reflects that units, such as Hawthorn, are expected to last 40 years. Hawthorn 1 - 4 are 33, 33, 29 and 27 years old respectively. KCPL was attempting to sell Hawthorn 1 and 2 capacity as late as November of 1984.

Based upon the evidence, the Commission finds that the Hawthorn units would be available to meet KCPL's load without the need for rehabilitation if it were not for KCPL's poor O&M and improper cycling practices. Wolf Creek displaces Hawthorn 1 - 4 capacity at a much higher cost per kw than the cost per kw associated with the full rehabilitation of the units. The units would be available for operation on natural gas, if timely remedial action had been taken to correct their physical condition.

Accordingly, the Commission determines that Hawthorn 1 - 4 should be accredited at Miliaras' near term base rating of 300 megawatts.

2. Montrose 1 - 3

The Montrose units were derated by KCPL in 1975, 1978 and 1981. A considerable reduction in the accredited capacity of Montrose 1 occurred in 1980. For 1975, all three units were derated by about 4.5 megawatts from the 1974 ratings. For 1978, all three units were derated due to age. In 1980, Montrose Unit 1 was derated 11 megawatts due to the removal for replacement of the steam turbines ninth stage buckets which were to be installed later. In 1981, Montrose units 1 - 3 were derated 12 megawatts, 24 megawatts and 20 megawatts respectively. KCPL's explanation for the 1981 deratings was that reductions in capacity were necessary to maintain excess air to avoid slagging.

Miliaras based his base ratings on capacity tests run on August 4, 1981 for Montrose Unit 1 and on August 21, 1981, for Montrose unit 2. During those tests Unit 1 achieved a net output of 159 megawatts and Montrose 2 achieved a net output of 162 megawatts. The comments on both tests stated that capacity was limited by induced draft fans. Miliaras states that the comparable value for the Montrose unit 3 is approximately 170 megawatts.

Company contends that its lower Montrose ratings are associated with the low quality coal burned at the units when compared to the original design coal and that the tests relied upon by Miliaras were run with better than normal quality coal.

The Commission determines that since the Company's tests show that the Montrose units can achieve Miliaras' near term base capacity accreditation, Mr. Miliaras' near term base value should be adopted. In the Commission's opinion these ratings are conservative as the November, 1981 Black and Veatch plant rehabilitation study show a greater capability for the Montrose 1 unit than the Miliaras' near term base recommendation. The Commission makes no finding as to the Company's practice of burning low quality coal in these units. However, the Commission notes that Company is replacing its coal supply for the Montrose and Hawthorn 5 units which could reduce capacity by 25 percent.

3. Hawthorn 5

The Hawthorn 5 unit generated 520 megawatts in 1972. In 1984 it sustained a load of 451 megawatts and the Black and Veatch plant rehabilitation study stated that the unit in 1981 had a maximum capability of 500 megawatts for short-term peak.

Company witness Cagnetta identified the original maximum capability of Hawthorn 5 as about 498 megawatts net and stated that the operation of the unit has been affected by two basic changes which have reduced maximum capability to 450 megawatts: (1) the balanced draft conversion and (2) the use of fuels other than the design fuel. Miliaras stated that he would expect a small derating in the net output of the unit due to the effects of the balance draft conversion. With respect to the design fuel, Hawthorn 5 was designed for River King coal from southern Illinois but at the time the unit was placed in service the coal was not available. Company witness Trask stated that Edna, Colorado coal with which more capacity could be achieved is not available in large volumes and does not appear to be cost justified.

Since Cagnetta testified that a 34 megawatt derating of Hawthorn unit 5 is a direct result of the unavailability of design coal, the Commission believes that the Company should be required to explain why the design coal, or something similar thereto, is not available. The record reflects that Edna coal is available in quantities to meet more than one-third of Hawthorn 5's needs and the Company has not produced any studies showing that Edna coal is not cost justified even though this information was requested by Staff.

Based on the above considerations, the Commission determines that the Company's 34 megawatt derating associated with the unavailability of design coal for the Hawthorn 5 unit should be rejected. Accordingly, the Commission determines that Hawthorn 5 should be accredited at 484 megawatts.

4. Northeast Combustion Turbines

At the time Miliaras compiled his recommended ratings for the Northeast Combustion Turbines he was lacking information regarding numbers 11 and 12. As a result, the ratings listed above for numbers 11 and 12 are lower than what he ultimately determined was appropriate. A 1973 Company letter indicates a base and peak rating for numbers 11 and 12 of 89.2 and 99.2 respectively. Thus, Miliaras determined that those values are appropriate for near term base and peak. These ratings are less than the 101 megawatt accredited ratings Company used in 1972 through 1974.

Miliaras' base rating for units 13 - 18 are based on a 1980 memo which agrees with the Northeast bid documents from which Miliaras took his peak ratings.

Having reviewed studies regarding the conversion to natural gas firing and the Black and Veatch plant rehabilitation study, Miliaras concluded that the addition of evaporative coolers to numbers 11 and 12 and the conversion to natural gas for 11, 12, 17 and 18 would add 12 megawatts to the Northeast combustion turbines for a total future rating of 415 base load and 488.6 peak load.

In addition, Miliaras testified that if the ratings of these CTs are adjusted for 95 degree ambient temperature, then near term and future ratings can be increased by approximately 1 megawatt per CT over his proposed ratings. MoKAN test procedures require testing at 95 degrees or above.

The Company contends that the eight units are located on a single site. Exhaust gases when the units are all running raises the site temperature, thereby limiting the output of the units. The reason site conditions limit the capacity of these units is that KCPL failed to lay out the site properly.

The evidence reflects that in 1977 the total output of all eight units at 95 degrees was 386 megawatts. In addition, Miliaras concluded that problems related to site conditions would be reduced or eliminated with the demolition of the retired steam station building which was occurring at the time of his visit.

The Commission notes that the Company contends that the Northeast CTs will be operated in the future to back up Wolf Creek. On the other hand, Company claims that the output is limited by site conditions and claims that improvements are not cost effective. The Commission is persuaded that the Company can get at least an additional 12 megawatts out of these units either by converting to natural gas, adding fans or improving site conditions. Therefore, adding 12 megawatts to the 386 proven output noted above, results in 398 megawatts for the Northeast combustion turbines. The Commission believes that since the Northeast combustion turbines are peaking units the base ratings that the Commission has accepted for these units are extremely conservative.

5. Total Accreditation

The Commission finds that the Company's fossil plant capacity accreditation is as follows:

Hawthorn 1-4	300 megawatts
Montrose 1-3	491 megawatts
Hawthorn 5	484 megawatts
LaCygne 1	343 megawatts
LaCygne 2	315 megawatts
Iatan	469 megawatts
Northeast CTs	398 megawatts
Total	2800 megawatts

In addition, it is agreed by the parties that 41 megawatts of the AEC exchange are available to meet peak load after June 1 of each year. Adding the 530 megawatts of Wolf Creek to the fossil capacity and the 41 AEC capacity, results in total capacity available to meet peak load of 3,371 megawatts.

B. Reserve Margin

KCPL proposes a reserve margin requirement of 22 percent. The Company has presented a reserve margin analysis performed by Herbert Limmer of Ebasco which results in a 23 percent reserve margin requirement.

Staff recommends a 22 percent reserve margin requirement based upon its study, performed by Frederick McCoy of Ernst and Whinney.

Public Counsel witness Rosen recommends a 15 percent reserve margin for ratemaking purposes. Jackson County also recommends a 15 percent reserve margin.

The reserve margin is the percentage by which the system's firm resources exceed peak hour demand. The reason for calculating a reserve margin is to ensure system reliability in case of an outage. Reliability is commonly quantified in terms of the probability that demand is expected to exceed available firm resources. Loss of load probability (LOLP) is expressed as the amount of time that demand will exceed resources during a 10-year period on an average or probabilistic basis given the particular system and its interconnection characteristics.

The Company's Ebasco analysis builds upon its reserve margin analysis presented to the Commission in Re: Kansas City Power & Light Company, 21 Mo. P.S.C. (N.S.) 543, 1977. In that case the Commission accepted the Company's asserted required reserve margin of 20.5 percent. This value was based upon the Ebasco study which concluded that the Company requires no less than 20 percent because of its system characteristics and the characteristics of the effective pool on which it draws emergency assistance. Company states that the 1980 study because of time constraints was not as elaborate as the present study.

The Ebasco study modeled a large pool composed of MoKan Group B of the Southwest Power Pool, two-thirds of Mapp and the Ilmo Companies of Main. Ebasco then identified the individual generators in the actual surrounding pools and assigned forced outage rates to the generators. Ebasco obtained historical simultaneous loads for a pool with a peak load of about 600,000 megawatts. Diversity assumptions were also established.

Ebasco then applied a two-area LOLP program to assess the impact of transmission limitations within the large pool. The study utilizes a loss of load probability (LOLP) criteria of one day in ten years or .1 day in one year. Ebasco concluded its approach demonstrated that the limits of the effective pool were reasonable inasmuch as pooling with areas to the southwest and north were known to be limited by transmission facilities.

After determining the pool reserve requirements, Ebasco allocated the minimum reserve margin to companies in proportion to their nonsimultaneous summer peak loads. Ebasco states that this process inherently accounts for load diversity within the pool, assures adequate pool reserves, and provides a basis for determining each pool members' reserve requirements. The study indicates a reserve requirement of 23 percent.

Staff witness McCoy utilized the Pices and Wasp models to arrive at appropriate reserve margins based on eight scenarios utilizing various assumptions concerning the inclusion of Hawthorn 1 - 4, Wolf Creek, and outage rates. For any given scenario the proposed reserve margin uses the highest of three approaches: (1) the 15 percent MoKan reserve margin requirement; (2) an LOLP analysis including a 2.5 percent load forecast uncertainty allowance; and (3) the largest unit out approach (the required reserve margin is equal to the largest unit on the system).

The Staff's proposed 22 percent reserve margin is based upon the following assumptions: (1) Miliaras' future base ratings for the fossil plants of 2,991 megawatts, including Hawthorn units 1 - 4 and excluding Wolf Creek; (2) KCPL's peak load forecast of 2319 megawatts for 1985; (3) KCPL's 1985-1986 SPO functional plan outage rates; and (4) the largest generating unit out approach.

Under McCoy's analysis the most significant factor affecting system reliability and consequently the reserve margin are the unit size, the amount of capacity support, outage rates and load forecast uncertainty.

Richard Rosen of Energy Systems Research Group, Inc. (ESRG) concluded that a 15 percent reserve margin is sufficient to provide reliable service for KCPL absent Wolf Creek. Rosen further concludes that with Wolf Creek added to the system, reserve requirements would increase to about 22 percent in order to maintain the same level of reliability.

Rosen performed an independent analysis, modeling the KCPL system separately in order to determine a one day in ten-year LOLP required reserve margin. To represent interconnections, Rosen calibrated the model employed by Ebasco.

Rosen's simulation of the 1992 KCPL system assuming Wolf Creek results in a 22 percent reserve margin. Excluding Wolf Creek and assuming the addition of combustion turbines produced a 15 percent required reserve margin. Another simulation assuming small coal-fired steam turbines in lieu of Wolf Creek produced a 16 to 17 percent reserve margin requirement. Rosen's study assumes a 500 megawatt limit on emergency transfers to KCPL.

In the Commission's opinion Ebasco's large effective pool reserve margin requirement does not determine the reliability of the KCPL specific system. The Commission also notes that Limmer was unable to adequately explain why Ebasco's 1980 study which calculated a 20 percent reserve margin differed from Ebasco's 1984 study which calculates a 23 percent reserve margin.

In the Commission's opinion it is appropriate to calculate the required reserve margin excluding Wolf Creek from the calculation. This is because it would be improper for Wolf Creek to justify its own need because of its effect on the reserve requirement.

Since the Commission has adopted lower system capacity ratings and has rejected the use of the Company's SPO functional plan outage rate for fuel purposes, the 22 percent reserve margin based on those assumptions calculated by Ernst and Whinney should be rejected.

In general, the Commission believes that McCoy's reserve margin calculations are conservative and calculate an overstated reserve margin. The largest unit out approach is overly conservative and unnecessary for the calculation of a reserve margin for an interconnected system such as KCPL. The Commission notes that the utilization of Miliaras' near term base ratings, assuming the largest unit out criteria and forecasted outage rates result in a 20 percent reserve margin under McCoy's study. Ignoring the largest unit out criterion and assuming LOLP only results in a 14.1 percent reserve margin assuming no additions to KCPL's system. Adding Hawthorn 1 - 4 to this scenario produces a required reserve margin of 25.1 percent. This result is apparently related to the reliability of the added units and the downward adjustment of available tie capacity in an amount equal to the additional capacity represented by Hawthorn 1 - 4.

The record reflects that most interconnected utility systems plan on the basis of a 15 to 20 percent reserve margin. Low load factor systems such as KCPL and the MoKan power pool favor relatively low reserve margins because scheduled maintenance can occur when reliability is high. In addition, MoKan has a reliability advantage because of the absence (prior to the inclusion of Wolf Creek) of nuclear facilities. The system is dominated by large numbers of relatively small generating units. The contractual reserve margin requirement required of MoKan members is 15 percent.

As Rosen points out maintaining a particular reserve margin is not an end in itself. The objective is a reasonable level of system reliability. The reserve margin is a rule of thumb which if developed properly will correlate with an acceptable reliability level. LOLP estimates are theoretical and in practice significantly overestimate actual generation related outages. This is because actual generation caused service outages are extremely rare.

Having considered all of the foregoing, the Commission determines that a 20 percent minimum reserve margin is reasonable and more than adequate for the KCPL system.

C. Traditional Excess Capacity

Based on the Commission's analysis of accredited capacity and reserve margins set forth above, the Commission finds that excess capacity exists on KCPL's system.

KCPL's asserted need for Wolf Creek can only be based on the Company's derating and retirements of its older fossil-fuel plants. Miliaras' testimony establishes that much of the Company's deratings and particularly the retirement of Hawthorn 1 - 4 are caused by the Company's poor operation and maintenance procedures.

In addition, Wolf Creek represents excessive base load capacity on KCPL's system resulting in serious minimum load problems. KCPL's 1975 generation studies raised questions as to the need for two large base load units represented by Iatan and Wolf Creek which were planned for 1980 and 1982 respectively. A Company document referencing the 1975 generation study recognized the requirement for peaking capacity on KCPL's low load factor system.

In order to determine the amount of excess capacity, the Commission believes that it is appropriate to use Public Counsel witness Talbot's ESRG high case peak load forecast. This forecast is based on an end-use model which disaggregates energy consumption and demand into its major components and subcategories. This approach models many uses separately thereby allowing any errors within the different categories to cancel each other out. ESRG's high case forecast assumes a 1.4 percent growth rate for peak demand to the year 2000. KCPL's peak load growth has been less than 1.4 percent since 1980.

The ESRG forecast does not differ greatly from KCPL's peak demand forecast until after 1993. KCPL's 85 MoKan forecast contained in Exhibit 327 shows the KCPL MoKan 85 forecast assuming a three percent real price increase over a five-year period to fully recover Wolf Creek. The forecast shows 2319 megawatts for 1986, 2396 megawatts for 1988 and 2467 megawatts for 1990. The ESRG high case forecast for the same years shows 2330 megawatts, 2410 megawatts and 2480 megawatts respectively.

Staff witness Viren's forecast under Staff's near term base rating assumes a higher forecast than KCPL's. This is because the Viren forecast assumes a 2.5 percent real price decrease in 1985 and 1.5 percent real price increase over an extended period.

The Company's and Staff's forecast are inordinately sensitive to price fluctuations because they reflect long run price elasticity in the short run. Viren stated the effects of long run elasticity are not realized for three to eight years. ESRG's end-use approach tends to overcome the short run elasticity problem.

Based on a 2330 megawatt peak load forecast for 1986 and assuming a 20 percent reserve margin results in 2796 megawatts of capacity needed in 1986. Based upon the accredited capacity found reasonable herein with the inclusion of Wolf Creek, 3371 megawatts of capacity is available resulting in 575 megawatts of excess capacity in 1986. This value exceeds the 530 megawatts of KCPL's share of Wolf Creek capacity.

Assuming the ESRG 2410 peak load forecast for 1988 results in 479 megawatts of excess capacity which is equivalent to 90.4 percent of KCPL's share of Wolf Creek.

Assuming the ESRG 1990 forecast of 2480 megawatts results in 395 megawatts of excess capacity. This represents 74.5 percent of KCPL's share of Wolf Creek. Thus the evidence before the Commission indicates that approximately 75 percent of Wolf Creek will not be needed as late as 1990.

Public Counsel argues that the risk sharing principles should be used as a basis for making a traditional excess capacity adjustment in this case. Public Counsel maintains that the Commission must balance the interest of ratepayers and shareholders and share the risk of excess generating capacity not needed to provide service to KCPL's customers. Public Counsel argues that the "used and useful" doctrine supports his proposed risk sharing approach.

Public Counsel cites a recent Pennsylvania case as an example of the application of the "used and useful" doctrine in the excess capacity situation. In Pennsylvania Public Utility Commission v. Pennsylvania Power and Light 55 P.U.R.4th 185 (1983), the Pennsylvania Public Utility Commission determined that Pennsylvania Power and Light possessed 945 megawatts of excess capacity associated with Susquehanna Unit No. 1. The Pennsylvania Public Utility Commission allowed Pennsylvania Power and Light to recover depreciation and other operating costs associated with the excess plant but would not allow the Company to earn a return on the net plant.

Public Counsel cites a more recent Pennsylvania case where the Pennsylvania Commission again addressed excess capacity associated with the Susquehanna Unit No. 2, Pennsylvania Utility Commission v. Pennsylvania Power and Light Company, 67 P.U.R.4th 30 (1985). In that case the Pennsylvania Public Utility Commission denied an equity return on 945 megawatts of Susquehanna Unit No. 2 until such time as the Company could show that the net benefits of the unit would exceed net cost of the unit or that the capacity was necessary for system reliability.

As noted above, Section I-A, Standard, a utility is entitled to a fair return on its prudent investment in property devoted to the public service. The "prudent investment" test and the "used and useful" test have been the basis of utility law since Smith v. Ames, 69 U.S. 466 (1898) where the court stated:

> ...the basis of all calculations as to the reasonableness of rates to be charged by a corporation maintaining the highway under legislative sanction must be the fair value of the property being used by it for the convenience of the public...What the company is entitled to ask is a fair return on value of that which it employs for the public convenience. 69 U.S. 466, 456 (1898)

The Commission agrees with Public Counsel's statement that the "prudent investment" test and the "used and useful" test are tools to be employed by regulators enabling them to set just and reasonable rates in light of their duty to balance the interests of the shareholders and the ratepayers.

The Commission has utilized the "prudent investment" standard in the the determination of the proper amount of Wolf Creek investment eligible for the inclusion in rate base.

The Commission believes that the "used and useful" standard is appropriate for the determination of the existence of excess capacity and adjustments related thereto. While prudence is relevant to an assessment of whether the excess capacity results from imprudent planning, the analysis does not stop there. Clearly, the results of imprudence should be excluded. However, the absence of imprudence does not dictate the total recovery of revenues associated with excess plant.

The Commission's duty to balance investor and consumer interests does not amount to a guarantee that utility management is operating in a risk free environment and thus the shareholder's investment is also risk free. Utility management took the risk that the Wolf Creek unit would not be needed when the construction plan was complete. The Commission recognizes that the Company has an obligation to provide for future electric needs of its customers. Thus, absent a showing of imprudence, a proper balancing of investor and ratepayer interests dictates that the shareholder should not bear 100 percent of the consequences of excess capacity. In an unregulated environment this would be the case. However, in an unregulated environment there is no obligation to serve.

Although the ratepayer has a right to demand service from the utility, the ratepayer is captive of the utility's monopoly power and must look to the regulator to protect his interest. The ratepayer does not participate in the Company's generation planning.

Although the Commission has made no specific imprudence adjustment with respect to the Company's generation planning, the record does reflect that the Company knew or should have known that the proper operation and maintenance of its fossil plants would delay the need for Wolf Creek and that it was taking the risk of having excessive base load capacity.

The Commission determines that it is proper to share the risks associated with the excess capacity between the Company's shareholders and ratepayers. Accordingly, the Commission finds that the Company should recover full depreciation, return on long-term debt, return on preferred stock associated with the Wolf Creek plant and a full return on 25 percent of the Wolf Creek rate base. However, the record reflects that 75 percent of Wolf Creek will represent excess capacity as late as 1990. Therefore, the Commission determines that the Company should receive one-half of the equity return on 75 percent of the Wolf Creek rate base. The Commission finds that this adjustment affords a reasonable sharing between the Company's shareholders and ratepayers. This sharing equitably distributes the risk associated with the excess capacity on KCPL's system.

The Commission believes that this adjustment is fair, reasonable and conservative, since the record reflects that all of Wolf Creek represents excess capacity in 1986 and 90 percent represents excess capacity in 1988.

The Commission's determination herein is supported by Missouri law. The Commission was upheld when it made an excess capacity adjustment in State ex rel.

Valley Sewage Company v. Public Service Commission, 515 S.W.2d 845 (Mo.App 1974). In that case the Commission allowed only 10 percent of the costs of an additional mechanical treatment plant to be depreciated. In upholding the Commission the court stated:

> Although the Commission included the full value of the additional treatment plant in the rate base, it felt constrained to balance the equities by only allowing 10 percent of the cost of the additional treatment plant to be depreciated in projecting the net operating income for ratemaking purposes. The Commission was seized with authority to properly weight the depreciation attendant to the additional treatment plant if the additional treatment plant was not reasonably necessary or essential to serve the Company's present customers. 515 S.W.2d 848, 852 (Mo. App. 1974).

Similarly in the instant case since the Wolf Creek plant is not reasonably necessary or essential to serve the Company's present customers, the Commission determines that a proper balancing of shareholder and investor interests requires the excess capacity adjustment adopted herein. This adjustment shall remain in force until it is determined that excess capacity no longer exists on KCPL's system.

D. 5.5 Percent Unsold Share of Wolf Creek

Staff also proposes an excess capacity adjustment related to the Company's ownership share of the unsold portion of Wolf Creek. Staff recommends that the Company's 5.5 percent ownership share of unsold plant be removed from rate base until that portion of the plant is needed. When the 5.5 percent interest of Wolf Creek is needed, Staff proposes that it be placed in rate base at depreciated book value.

Staff contends that KCPL should not recover revenues associated with that portion of the capacity which is not currently needed and was not intended to be used to provide service to KCPL customers. As noted in Section I-B above, at the time KCPL and KGE decided to construct Wolf Creek, 17 percent of the capacity was to be sold to KEPCO. Only 6 percent of Wolf Creek was ultimately sold, resulting in a 47 percent ownership share for KCPL rather than the 41.5 percent which was originally contemplated.

Since the Commission has adjusted for excess capacity utilizing the risk sharing approach discussed above, Staff's excess capacity proposal associated with KCPL's 5.5 percent unsold ownership share should be rejected.

III. Test Year

Company and Staff agree that the appropriate test year to be utilized in this case is the 12-month period ending December 31, 1984. At the time briefs were filed in this case an issue existed regarding the true-up proceeding. This issue has since been resolved and on January 24, 1986, the Commission issued an order stating that no true-up proceeding would be held and ordering the parties to file a reconciliation of their respective cases.

The Company proposes adjustments to the 1984 test year reflecting the effect of Wolf Creek on Company operations and a July, 1985 payroll increase.

Staff's test year results are encompassed in Staff's Cases A, B and C. Case A reflects the test year with no post test year adjustments. Staff's Case B reflects adjustments of the following items to October 1, 1985: plant in service, depreciation reserve, materials and supplies, fuel inventories, deferred income tax reserve, revenues, fuel, payroll, depreciation, property taxes and income taxes. Cases A and B do not include Wolf Creek and its effect on revenue requirement. Both Cases A and B show a revenue reduction.

Staff's Case C shows Staff's proposed revenue requirement reflecting the effect of Wolf Creek on Case B. Thus, Case C reflects the incremental revenue requirement above the Case B revenue requirement.

Company opposes Staff's Cases B and C approach on the ground that Case B includes deferred tax reserves and certain cost savings associated with Wolf Creek. In addition, Company contends that Case B does not reflect the investment required to refurbish Hawthorn 1 - 4, does not reflect O&M expenses required to operate without Wolf Creek and does not reflect additional capacity required to meet load without Wolf Creek. Because of these alleged shortcomings, Company argues that Case B underestimates Company's revenue requirement without Wolf Creek and overestimates the difference between cases B and C in terms of the revenue requirement associated with Wolf Creek.

Staff's Case B does not assume that Wolf Creek had never been built. It measures a revenue requirement prior to the inclusion of Wolf Creek; in other words, a non-Wolf Creek revenue requirement. The record reflects that the Company has been earning in excess of its authorized return since August, 1983. Thus, were it not for the inclusion of Wolf Creek into rate base a revenue reduction would be appropriate. Case B attempts to calculate the appropriate "non-Wolf Creek" revenue reduction prior to the inclusion of Wolf Creek. The Commission believes it is appropriate to disaggregate the non-Wolf Creek and Wolf Creek revenue requirement in order to reflect any appropriate revenue changes associated with non-Wolf Creek plant prior to calculating the Wolf Creek related increase.

Company's arguments regarding deferred tax reserves and non-Wolf Creek costs which have been omitted from Case B misunderstand the Case B approach. These arguments assume that Case B represents a scenario where Wolf Creek is assumed to have never been built. The Commission has consistently approved the use of deferred tax reserves related to AFUDC as a rate base offset for this Company. Thus, it is appropriate to treat deferred tax reserves as a rate base offset in Staff's Case B.

Since Case B reflects the 1984 test year actual operations as adjusted, Case B is a reasonable calculation of the non-Wolf Creek revenue requirement immediately preceding the addition of Wolf Creek. Thus, additional costs related to operations without Wolf Creek should not be included in Case B.

Based on the foregoing, the Commission determines that Staff's Case A, B and C approach is appropriate and should be adopted.

IV. Operating Income

A. Payroll Expense

In determining payroll expense, the Company adjusted its actual 1984 test year payroll expense to an annualized payroll expense based on its level of employees on December 31, 1984, and the wage rates anticipated to be in effect on July 1, 1985. The rates for union employees were based upon the last Company offer to each union local. The rates for management employees were based upon the average pay rate for management employees included in the Company's 1985 budget.

Staff annualized the Company's 1984 payroll expense for employee levels and pay rates in effect December 31, 1984. Staff then adjusted that payroll expense to reflect actual employee levels and pay rates as of April 30, 1985. Next, Staff normalized that adjusted expense for wage increases expected to occur by September 30, 1985.

Staff's proposed payroll for management employees reflects an average management salary increase based upon the average of the proposed wage increases for the Company's three collective bargaining units, utilizing April 30, 1985, personnel levels. This limits wage increases to management employees to five months of the most recent offers made by the Company to its union employees.

Staff then applied a slippage adjustment to the management employee wage rate increase. Slippage is the difference between the average merit increase percentage for a group of employees and the percentage increase in average salary for that group of employees. An example of slippage would be where an employee making $24,000 annually leaves the Company and a new employee takes his place for $20,000 annually. This would tend to lower the rise in the average rate of pay for the entire group.

The Company objects to Staff's normalization. To the Company, one objectionable portion of the Staff's normalization is the limit Staff imposes upon the management wage increase occurring from April 30, 1985, to September 30, 1985. The Company contends it is unreasonable to allow a management wage increase for that period which only reflects the wage increase offered by the Company to its bargaining unit employees. The Company maintains there is no reason to tie one to the other. Company further maintains higher salary increases are neccessary to attract, retain and motivate qualified employees; however, Company did not provide evidence that it has incurred these problems.

The Company also objects to the Staff's utilization of the slippage factor concerning management-related payroll expense. The Company contends that Staff's slippage adjustment is not calculated on the true average annual slippage which occurred at the Company over the last five years, because it reflects the addition of employees above the number existing in the group at the time initial wage increases were granted.

In support of its position, Staff points out that the Company has indicated it does not have a turnover problem with management employees at current salary levels. Thus, it has not been shown that higher salary levels are necessary. Staff further maintains its slippage adjustment properly reflects the slippage incurred by the Company in the historical period studied.

For the above reasons, the Commission finds Staff's normalization proposal tying management salary increases to those increases offered collective bargaining units is appropriate based upon the operations of this Company. If the Company was losing middle to upper level management personnel due to pay compression, then this proposal might not be appropriate. In the instant case, the Company has not exhibited signs of excessive turnover in its middle and upper level management due to acceptance of higher paying jobs.

The Commission will next focus upon Staff's proposed slippage adjustment. The Commission believes that if Staff had not made a slippage adjustment, annualized payroll would be overstated by an amount proportionate to the slippage factor. Had the Company experienced a decreasing trend in its level of management employees over the 1979 to 1984 period used by Staff, Staff would have made no slippage adjustment.

That is due to the fact that payroll would be overstated since the actual payroll would be less than that built into rates. The Commission finds it is reasonable and necessary to utilize a slippage factor in a case such as this, where the Company's level of management employees has increased. Therefore, the Company's proposal is deficient for not accounting for a slippage factor.

The information used by the Staff to perform its slippage adjustment was taken from documents submitted annually to the Company's president. The Commission's calculations were substantially similar to those of the Company, the difference being the Staff's calculation of a five-year average. The Commission believes the Staff's calculation is an accurate reflection of the slippage encountered by the Company from 1979 to 1984. Staff properly projected the employee levels to October 1, 1985, and maintained a constant wage level from April 30, 1985, to September 30, 1985. The Commission finds that to be reasonable. Hence, the Commission is not persuaded that Staff's method is flawed. Staff's method of calculating slippage is a more accurate and reasoned approach to establishing payroll expense than is a simple prediction of payroll expense, such as the Company proposes, with no slippage adjustment.

B. Deferred Credit Associated with Wolf Creek O&M

DOE proposes that the O&M savings achieved during the test year be credited and amortized over a period of five years. The Company opposes DOE's adjustment on the ground that such O&M savings are already reflected in the adjusted test year and thus the amortization would constitute double counting of the savings.

Based on 1984 O&M savings of $6,457,000, DOE assumes the same level of savings in 1985 resulting in a total savings of $12.9 million for the two-year period.

DOE argues that this amount represents non-recurring savings and should be treated in the same manner as non-recurring extraordinary expenditures. DOE argues that KCPL should not be allowed to retain these excessive earnings.

In the Commission's opinion the O&M savings at issue are not comparable to one-time non-recurring extraordinary expenditures. The Company's rates which have been previously set by this Commission are designed to recover O&M expenses among other expenses and a return on the Company's investment. The Company apparently did not incur O&M expenses at the level that was built into previous rates. The Commission finds that DOE's proposal involves returning past profits to ratepayers in violation of the prohibition against retroactive ratemaking and, therefore, should be rejected.

C. Storm Damage Reserve

The Public Counsel recommends that the Commission establish a storm damage reserve account to recover the cost of future storm related expenses. Public Counsel proposes $970,079 on an annual basis based upon a normalization of expenses associated with significant storms occurring since 1973. The Public Counsel contends that this approach legally addresses extraordinary storm expenses and avoids Public Counsel's claim that the amortization treatment of storm-related expenses constitutes retroactive ratemaking.

Since the Commission has rejected Public Counsel's retroactive ratemaking argument and found the amortization method to be appropriate, the Commission finds that Public Counsel's proposal to establish a storm damage reserve account should be rejected.

D. Test Year Revenues

The Company adjusted its test year revenues to reflect known and measurable changes, including the annualization of test year kilowatt hour sales and revenues, to reflect the projected number of customers as of July 31, 1985. Company's calculated test year revenue level is approximately $359.8 million. The Company's approach is consistent with the method proposed and adopted in Case No. ER-83-49.

The Staff proposes to normalize and annualize test year kwh sales by applying to the Company's actual test year Missouri load factor the base case projection of peak demand that appears in the Company's May 1984 econometric analysis. Staff's proposal is the same approach it has recommended in the Company's last three rate cases. The Commission adopted Staff's position in Case Nos. ER-81-42 and ER-82-66. Staff's calculated test year level is approximately $359.7 million.

Company is critical of Staff's method primarily because it applies an actual 1984 load factor which has not been weather-normalized to a projected 1985 peak load that has been weather-normalized. Company argues this method cannot result in a true normalization. Company further faults portions of Staff's method as presenting a biased estimate.

There is little difference in the actual level of revenues determined by Staff and Company. Therefore, the issue to be decided is whether Staff or Company's method is the most appropriate to utilize for determining a reasonable level of revenues. In the Company's last rate case, the Commission changed from its previous position of annualizing and normalizing test year kilowatt hour sales and thus, test year revenues. The Commission deviated from that method because of the tremendous potential of revenue loss to the Company from loss of Amoco as a major customer. At the time, the Commission believed the Company would be unable to offset the revenue loss when Amoco ceased to be a customer. Staff's proposal in that case did not properly account for the loss of Amoco as a customer and resulted in an overstatement of annualized revenues. To prevent such an overstatement, the Commission found, in that case, that it was "proper to make an allowance for the loss of a single load of Amoco's magnitude." Re: Kansas City Power & Light Company, 26 Mo. P.S.C. (N.S.) 104, 113 (1983). In this case there is no similar potential for loss of a major customer. Thus, there is no reason to continue use of the Company's method, particularly in light of the fact that lost revenue due to Amoco's reduced load was more than compensated for by increases in various customers' usage.

The Commission is of the opinion it is more appropriate to utilize the Staff's method, which accounts for several variables that may affect revenue, such as changing customer usage, weather and economic growth, rather than the Company's method, which annualizes based upon changes in customer levels. The Commission is not persuaded by the weather-normalization argument of the Company. The Commission finds load factors have remained somewhat constant historically in spite of the weather. The Commission believes Staff's method is a more accurate and reasonable way to determine the level of test year revenues than Company's method. The evidence indicated that changing customer usage has historically had a larger impact on sales than changes in customer levels. Changing customer usage levels are not reflected in the Company's method. For the above-stated reasons the Commission is adopting Staff's method of determining test year revenues. The Commission notes this is consistent with several of its past decisions. The Commission's deviation from this position in Case No. ER-83-49 was based upon a unique and distinguishable set of facts.

E. Wolf Creek Property Insurance

Public Counsel recommends an equal sharing of nuclear property insurance expense between the shareholders and the ratepayers. If such a sharing is not adopted, Public Counsel suggests that an adjustment should be made to the amount of property insurance expense allowed which is proportionate to the amount of any imprudency adjustment adopted by the Commission.

This issue between the Company and Public Counsel is almost identical to the property insurance issue determined in Phase III. The Commission rejected Public Counsel's arguments there, and must once again. The Commission believes it is more in the ratepayers' interest to include property insurance as a part of the Company's cost of service, rather than to share the expense with the shareholders. See the Commission's discussion, Phase III, II.F., Property Insurance, above. The Commission finds it is prudent management on the part of the Company to maintain such insurance. The Commission is of the opinion that property insurance costs are a necessary operating expense and therefore should be recoverable.

Since the Commission has found it is prudent to maintain this type of insurance, it is inappropriate to deduct a portion of it for imprudency adjustments in other areas of this case. The two are unrelated. Therefore, the Commission is rejecting Public Counsel's proposal.

F. Property Taxes

Initially, Staff and Company disagreed as to the effect calculating plant gross of tax on Wolf Creek would have on the property amount owed. Staff contended that as the assessed value increased, the tax levy would decrease to the degree that the overall resultant property tax would be the same. Company maintained an increase in the assessed value would increase the property tax owed.

Company did not brief this issue and stated in Exhibit 612 that it intended to concede this issue to Staff. The Commission is, therefore, adopting Staff's position.

G. Hawthorn 5

In the Company's last rate case, Re: Kansas City Power & Light Company, 26 Mo. P.S.C. (N.S.) 104 (1983), the Commission accepted Staff's and Company's proposal to amortize the cost of repair and replacement power associated with a forced outage at the Company's Hawthorn 5 generating unit. In adopting Company and Staff's amortization, the Commission rejected Public Counsel's assertion that the Hawthorn 5 outage resulted from negligence and management failure.

In the instant case Staff has attempted to relitigate the Hawthorn 5 outage issue and now proposes that no costs attributable to the Hawthorn 5 outage be recovered.

Although the Commission is not bound by the doctrines of res judicata and collateral estoppel, the Commission has the discretion to apply the doctrines to avoid needless relitigation of issues.

Kenneth Culp Davis explains the application of the doctrine of res judicata and its distinction from collateral estoppel in his hornbook, Administrative Law, West Publishing Company 1978, p. 432:

> The traditional doctrine of res judicata as applied in the judicial system is inexorable in making a judgment binding so as to shut off further inquiry no matter how clear the mistake of fact or how obvious the misunderstanding of law or how unfortunate the choice of policy or how unjust the practical consequences or how inadequate the evidence in the record or how poorly prepared the briefs and arguments. The interest of parties and of the public in ending litigation normally bars a party who has had his day in court from further pressing the same claims or the same defenses. Under the principles of bar and merger a judgment for the defendant bars the plaintiff from again asserting the same claim and a judgment for the plaintiff prevents the plaintiff from trying to get more, the theory being that the cause of action has merged in the judgment. When a cause of action is merged in or barred by a judgment, the judgment is binding no matter what issues were or were not actually litigated; it is binding even as to matters which might have been but were not actually litigated. The doctrine of collateral estoppel is different from merger and bar in that instead of preventing a second assertion of the same claim or cause of action, it prevents a second litigation of the same issues between the same parties even in connection with a different claim or cause of action.

The criteria for applying res judicata and collateral estoppel are set out generally by the U.S. Supreme Court in United States v. Utah Construction and Mining Co., 86 S. Ct. 1545 (1966), and more specifically in Athan v. PATCO, 672 F.2d 706 (CA 8 1982). The Athan court set out four criteria:

1) issue must be identical to one in a prior adjudication;

2) there was a final judgment on the merits;

3) the estopped party was a party or is in privity with a party to the prior adjudication; and

4) the estopped party was given a full and fair opportunity to be heard on the adjudicated issue.

Because of the nature of administrative proceedings, courts were originally reluctant to apply the doctrines at all. This reluctance, though, has been moderated and the more accepted view now is that the doctrines are applicable if they serve the purposes for which the doctrines were established and do not create an unjust result. The reasons behind the application of the doctrines in the court system are applicable to some administrative decisions.

The U.S. Supreme Court has set out the same view of the doctrines' application to administrative decisions in the Utah Construction and Mining case. The court stated that:

> . . . occasionally courts have used language to the effect that res judicata principles do not apply to administrative proceedings, but such language is certainly too broad. When an administrative agency is acting in a judicial capacity and resolves disputed issues of fact properly before it which the parties have had an adequate opportunity to litigate, the courts have not hesitated to apply res judicata to enforce repose. (Cases cited not listed).

In the Utah Construction and Mining case, the court precluded further proceedings because of a prior administrative decision.

The Hawthorn 5 issue is identical to the issue tried in the Company's last rate case. The Staff had a full and fair opportunity to litigate the Hawthorn 5 issue in that rate case. Based on the evidence, the Commission found for the Company and the Staff. In the instant matter the Staff has shown no changed circumstances or new evidence not available to the Staff at the time of the Company's last rate case.

Accordingly, the Commission determines that relitigation of the Hawthorn 5 issue is not appropriate. Therefore, the Commission will not address the merits and Staff's adjustment is rejected.

H. Netting of Ice Storm, Edison Credit Union Sale and Two Capacity Sales

Staff proposes to net the 1984 ice storm expense against the gain from the Edison Credit Union land sale and two capacity sales. Staff then proposes to amortize the net amount over a five-year period. Company takes the position that the Staff's treatment is against precedent and capacity gains should not be deferred. The Company does not address the issue in its brief.

Staff argues that since the ice storm, the land sale and the two capacity sales are extraordinary events, it is reasonable to net the amounts associated with these events and amortize them over a five-year period.

Since the Company has built no capacity transactions into this case and since the amount of damages associated with the ice storm were affected by a reduction of the Company's tree trimming program, the Commission determines that it is appropriate to net the 1984 ice storm expense against the two capacity sales as proposed by Staff and amortize the amount over a five-year period. The Edison Credit Union land sale shall be excluded from the calculation, since Company's below the line treatment of the land sale has been accepted by the Commission.

I. Wolf Creek O&M Expense

The amount Company is seeking to include in rates for Wolf Creek operation and maintenance (O&M) expense is based the KG&E O&M budget. The Company disagrees with 13 of the Staff's proposed adjustments to that budget. All dollar amounts proposed to be disallowed are on a total plant basis.

1. Payroll Expenses

Staff recommends a $3,750,922 downward adjustment be made to KG&E's budgeted payroll expense due to the Company's failure to support that expense level. Staff encountered difficulty obtaining the information necessary to audit this area. Although supplied with a computerized Labor Rid showing payroll by position, Staff was unable to utilize it properly because the Company requested its return. Company claims a telephone call with the NRC indicated that the Labor Rid contained information regarding security personnel to which access should be restricted. The document then given to Staff was altered in such a way that Staff was unable to even determine if payroll amounts belonged to KG&E Nuclear Department personnel. Staff requested that the information pertaining to security personnel simply be deleted so that Staff could use the information pertaining to nonsecurity personnel. Company originally refused to provide this information. Once it was provided, it was too late for Staff to use prior to its filing.

Staff attempted to use the KG&E Nuclear Department staffing schedule to determine if the number of positions was reasonable, but it was never given the requested information regarding justification of newly-added positions. Due to its inability to adequately audit this area, Staff recommends the Commission adopt the level of expense allowed for O&M expenses for UE's Callaway plant in the company's most recent rate case.

Company argues that Staff's problems could have been alleviated had Staff asked the NRC for a grant of access to the information. Company further argues that use of the O&M expense from Callaway is inappropriate in this case. Company contends that the difference in the method of accounting for certain expenses at Wolf Creek and Callaway alone is enough to offset Staff's proposed disallowance. Company points out that the Wolf Creek security force is staffed by direct-hire personnel whose salaries are accounted for in KG&E payroll expense. The security force at Callaway is not in the direct labor budget, as it is staffed by a contractor.

The Company maintains Staff had adequate information to determine the reasonableness of the labor budget "considering that the payroll expense of a sizeable security force must also be met." Company believes Staff's recommended level of payroll expense is inappropriate because Staff is ignoring the fact that UE revised its Callaway O&M budget after its rate case.

The Commission is of the opinion that Staff's difficulties in obtaining information from the Company impeded its ability to adequately audit the budgeted amount of payroll expense. The Commission finds it was the Company's responsibility to seek a grant of access from the NRC to allow Staff's audit. At a minimum, it was Company's obligation to give Staff the necessary records pertaining to nonsecurity personnel in a timely manner. Neither occurred. As a result, it was impossible for Staff to determine a reasonable level of payroll and staffing from the Company's records. Therefore, it was reasonable for the Staff to turn to an alternative level of expense.

The evidence indicates that Staff was not informed of the revised Callaway O&M budget and the reconciliation of the Callaway and Wolf Creek O&M budgets performed by KG&E's budget group until an April 12, 1985, meeting with the Company. Approximately two weeks later, Staff asked for and received a copy of the reconciliation. Since Staff did not receive the reconciliation until after its field audit was completed, it has not relied upon that information. The Commission is of the opinion it was appropriate for Staff to reject the updated information. Had Staff accepted the resulting reconciliation on blind faith, it would have been forced to make a recommendation based upon the unaudited reconcilation. The Commission has previously adopted a reasonable level of O&M expenses for the Callaway plant and believes that determination is a reasonable one upon which to fall back in the event it is impossible to adequately evaluate certain portions of the KG&E O&M budget. Such is the case here. Staff's recommendation affords the Missouri ratepayers more protection than does use of the unaudited reconciliation. The fact that Callaway's accounting methods differed in some areas from those used at Wolf Creek is unfortunate; however, Staff would not have had to resort to that data had it been able to perform a full audit. The Commission is not finding that the payroll amount budgeted for the security or nonsecurity personnel is unreasonable, but instead that it was unauditable and that no determination of reasonableness could be made. Since the Commission recognizes the fact that some level of payroll expense is necessary, it does not find it reasonable to disallow all of the Company's budgeted payroll expense, and therefore adopts Staff's proposal.

2. Management Systems

Management Systems includes: Records Management, Document Control and Configuration Management. The Company proposes to allocate the Management Systems expenses between Operations, which are expensed, and Construction, which are capitalized. Based upon the Company's admission that only 16.9 percent of the documents processed by Records Management are anticipated to be of an operational nature, Staff recommends that 17 percent of the Management Systems expenses be allocated to Operations and 83 percent be allocated to Construction. This results in a reduction in O&M expenses of $257,940. Staff supports the reasonableness of its estimate by pointing out that the Configuration Section works closely with the Nuclear Plant Engineering Section, which allocates 20 percent to expense and 80 percent to capitalization.

The Company generally argues that Staff did not closely evaluate each of the Management Systems sections or it would have realized the 50/50 split proposed by Company is appropriate.

It is obviously easier to estimate an equal allocation than it is to obtain a reasonably accurate figure of the amount to be expensed versus the amount to be capitalized in Management Systems. Since there is not enough evidence before the Commission to indicate an exact allocation, the Commission must determine the most reasonable estimate of the appropriate allocation between Operations and Construction. Company's listing of the functions of the various systems does not designate or allocate between the Operations and Construction functions. The Commission believes the Staff's estimate is a more reasoned and supported amount than that of the Company. Staff's recommendation corresponds to a $257,940 disallowance.

3. Business Specialists

The Staff seeks a $557,622 disallowance for Business Specialists who were hired due to the volume of work caused by turnover of construction and start-up records. Staff contends the Business Specialists were hired as temporary help and will no longer be on the job site after November 1985. The disallowance represents the one-time nature of the Business Specialists' tasks.

The Company maintains the Business Specialists performed various functions which will continue after commercial operation and must be performed either by KG&E people or Business Specialists.

The Commission finds Staff's adjustment is necessary and reasonable since the Business Specialists were retained only on a temporary basis and their predominant function will eventually cease.

4. Training Consultants

The owners have budgeted $2,160,000 for the first year budget for training consultants. Staff proposes a $1,728,000 reduction of O&M expense which reflects a five-year normalization of the budgeted amount. The budgeted amount is segregated into two elements: Program Development and Classroom/Simulation Instruction. The program development consultants were hired in order to meet accreditation commitments made to the Institute of Nuclear Power Operations. The classroom/simulator instructors were hired to teach licensed operators until sufficient levels of qualified personnel are available to replace the consultants. The consultants will no longer be needed after 1988.

Staff proposes to normalize these expenses because they are one-time costs which, if included as O&M expenses, would cause expenses to be abnormally high.

Company maintains that although the consultants will no longer be needed after 1988, the training expense will continue in-house throughout the life of the plant. Company further maintains that Staff inconsistently applies its normalization philosophy to various issues in this case.

The evidence established that the cost incurred for these consultants would decrease yearly until 1988 when they will be eliminated entirely. The people taking the classes will then be able to teach the classes. It does not appear that additional expense will be necessary once an adequate number of personnel are trained. The Commission determines the Staff's recommended normalization is the most appropriate method of recovering these expenses, particularly since the Commission is adopting the phase-in proposal described in Section IX below. The Commission finds that Staff's normalization philosophy is not inconsistently applied throughout the O&M budget, nor throughout this case.

3. MATSCO Testing

According to Staff, MATSCO was retained to perform the abnormally high number of tests required in Wolf Creek's first year. To properly account for that expense, Staff recommends a five-year normalization, which reflects a $2,912,000 downward adjustment to the O&M budget. Staff maintains that a failure to normalize would overstate the Company's revenue requirement. Once again, the Company contends that Staff's normalization philosophy is applied inconsistently. Company further contends that MATSCO technicians perform functions other than testing; nonetheless, the testing level will vary from year to year but will continue at some level each year. It will be necessary either to perform the tasks in-house or to hire a consultant. Company believes the costs should be recovered as incurred.

The record reflects the number of tests that will be performed in Wolf Creek's first year of operation is 15 times greater than any other year. The evidence demonstrates that MATSCO technicians will not be retained after the first year of operation. This issue is similar to the issues of Training Consultants and Business Specialists previously discussed. It does not appear that additional consultants will be needed to perform the testing once the first year testing is completed. Company has not retained MATSCO after the first year of operation and no evidence was presented to indicate that another consultant definitely will be hired. Neither was evidence presented of additional costs necessitated by in-house staff performing the various functions. The Commission finds the Staff's normalization to be appropriate and consistent with that adopted by the Commission in Section IV.I.4. above.

6. Security Clearances

Security clearances are performed on all prospective employees in the Nuclear Department. By recommending disallowance of $24,000, Staff proposes to eliminate costs associated with security clearances after commercial operation. Since Staff has received no justification of any additional positions, as discussed Section IV.I.1, Payroll Expenses, above, Staff does not recommend the Commission allow any additional expense for security clearances.

The Company faults Staff for not accounting for departmental turnover.

The Commission believes the Company's position is more reasonable than Staff's in this instance. It is clear that the Nuclear Department will experience some level of turnover and those new employees will need security clearances. The Company should be allowed the amount necessary to provide those clearances.

7. Plant Manager Miscellaneous Costs

Staff proposes a $79,998 disallowance for various costs included in the O&M budget from the plant manager because the owners refused to furnish information on certain items they deemed as safeguarded. Those safeguarded areas are: Uniform Cleaning, $25,029; Bomb Disposal Training, $15,017; Security Professional Development, $15,017; Weapon Repairs, $5,006; and Uniforms, $20,023.

It is the Company's contention that Staff could have sought a grant of access from the NRC to obtain the information sought. Since it did not, Company does not believe the Commission should adopt the recommended disallowance. The Commission determines it was up to the Company to obtain some sort of determination from the NRC in order to grant the Staff access to information involving these items. The Company seemingly forgets that it is the entity requesting rate relief and that Staff cannot perform its statutory duties if unduly prohibited from examining the Company's books and records. The Staff had no difficulty in this area with Union Electric Company during its investigation of the Callaway plant. Since it is the Company's interpretation of 10 C.F.R. Part 73 that denies Staff access, it is up to the Company to obtain a formal interpretation from the NRC. If Company is correct, it should have attempted to obtain a grant of access for Staff so that an audit could be performed to determine the reasonableness of the expenses. It is clear the Staff is not going to recommend an expense be allowed that cannot be audited or supported. Neither will the Commission allow one such as this. The Commission finds Staff's disallowance to be reasonable.

8. Miscellaneous Materials

This category generally covers office supplies and materials. Staff recommends a $5,996 disallowance because Company did not justify its costs nor provide its method of calculating such an expense.

The Company claims it had no historical data from Wolf Creek upon which to base this category of expense. It was, therefore, necessary for the budgeter to use his own experience and judgment. The Commission believes the Company's method of estimating was adequate in this instance.

9. Office Equipment - Sperrylink Equipment and Copiers

It is Staff's recommendation that $72,096 be disallowed to eliminate certain equipment which was budgeted to be necessary due to future expansion. The equipment is currently in use. Hence, it is now an expense item of the present plant. In light of that change in circumstances, Staff has failed to raise a serious doubt as to the reasonableness of the expenditure. The Commission is of the opinion that Staff's proposed disallowance should be rejected.

10. Consultants to Director of Nuclear Operations

$120,000 was included in the KG&E O&M budget as a provision for outside consulting services that might be needed by the Director of Nuclear Operations. Company justifies this expense item by asserting the Director has broad responsibilities which might require special expertise from outside sources.

Staff argues that the Company's reasoning exhibits nothing more than speculation. Staff further argues that creation of a "rainy day" type of fund is an inappropriate ratemaking principle.

The Commission was unable to discover from the testimony any specific problems which would require outside consultant help. Clearly, such problems are unknown at this time. The Commission agrees with Staff's characterization of this subissue as one of speculation. The Director of Nuclear Operations is admittedly a highly qualified individual who must surround himself with equally qualified staff help. Theoretically, that should be adequate. Since no problems requiring outside consultants can be identified at this time, the Commission is disallowing the proposed budget item.

11. Spare Parts

Staff originally proposed to amortize the budgeted amount of spare parts over the 40 year life of Wolf Creek. Subsequent to Staff's direct filing, the owners withdrew their original support of figures submitted by them as representative of spare parts inventory. The Staff now contends the budgeted expense level for spare parts is left without foundation and recommends the Commission disallow it in its entirety.

The Commission agrees with Staff's reasoning and is adopting Staff's position. Discussion of the Commission's reasoning is more fully set out in Section IV.J., Spare Parts.

12. Nuclear Insurance

This subissue pertains to the $1,855,920 amount budgeted to purchase Replacement Power Insurance from Nuclear Electric Insurance Limited (NEIL). The Company believes this type of insurance is necessary. Without this insurance, the Company asserts a prolonged outage at Wolf Creek would force it to purchase higher-cost power from other sources to replace Wolf Creek power. Company points out the NRC has issued 96 operating licenses. Of those 96 reactors licensed, 86 are insured under NEIL I. Company bases its decision to buy NEIL Replacement Power Insurance on the fact there is a "non-zero probability of a catastrophic loss occurrence" demonstrated by the TMI incident.

Staff proposes total disallowance of these premium costs for several reasons. Staff maintains this expense item has not been justified by the owners and the owners have conducted no study which indicates that the coverage is cost justified. Staff believes inclusion of this type of expense in rates would allow companies to circumvent certain ratemaking considerations. The Staff further maintains the insurance coverage is a potential liability rather than a benefit to the participating companies due to the potential of retroactive assessments.

This type of insurance consists of member companies paying premiums into a type of pool or surplus. In the event of an accident, benefits would be paid from the surplus. Those benefits would not be payable until 26 weeks after the incident causing the outage occurred. If the amount paid out to any of the member companies exceeds the surplus, each of the companies will be assessed an additional amount.

The Commission does not believe it is in the best interests of the Missouri ratepayers to subject them to the potential payment of additional expenses to cover claims from other companies. There are no studies to indicate the probability of an incident which would result in a prolonged outage of 26 weeks or more, yet the Commission is of the opinion it is not a frequent occurrence. Should the Company experience such an incident, it would be able to apply to the Commission for emergency rate relief or request, in a later rate case, that resulting costs be amortized over several years. It is unnecessary to discuss any of Staff's other reasons for disallowance. The risk of retroactive assessments to the Company's ratepayers to pay claims of other companies is adequate to demonstrate the reasonableness of the disallowance.

13. Escalator Factor

The Staff recommends the disallowance of the budget escalator which was applied to the O&M budget due to its speculative nature and its inappropriate calculations and application to the budget. According to Staff, this represents a $3,120,151 disallowance. Staff witness Cox originally testified that the owners used an overall 6 percent escalation rate, which compounded on a monthly basis to result in a 7.875 percent annualized rate.

Staff believes the escalator factor eliminates any incentive for the Company to offset any inflationary cost increases through increased productivity or expertise. Staff asserts the escalator factor was inappropriately applied to costs that will either decrease or be terminated in future years.

The owners used projections developed by Data Research, Inc. (DRI) for their escalations. DRI indicates a 6.1 percent escalation rate for Labor expenses and a 4.8 percent escalation rate for Other Than Labor expenses would be appropriate. Company utilized an escalation rate for Labor expenses and Other Than Labor expenses of 6 percent and 4.3 percent, respectively.

Company asserts Staff neglected to consider that the budget was prepared in 1984 dollars. Company contends that had Staff escalated the base dollar amount to April 1985 dollars and then performed its calculations, it would have arrived at a 4.8 percent figure. Company further contends the actual amount of escalation included in the O&M budget was $2,762,543.

Admittedly, the Company originally gave Staff inaccurate information to work with and the corrected information was not given to Staff until it was too late to utilize in its direct case. The Commission finds the corrected information demonstrates a 4.8 percent escalation rate. The Commission is of the opinion an escalator factor should be built into certain portions of the KG&E O&M budget. Although the Commission believes an escalator factor should be allowed, the Commission believes the Company's figure is somewhat high. The Commission is of the opinion an appropriate escalator factor would be near the rate of inflation. The Commission notes the inflation rate has fluctuated between 3 percent and 4 percent during the last year. The Commission finds an appropriate escalator factor would be 4 percent. The Commission further finds that it should not be applied to those areas of expense in the KG&E O&M budget which are decreasing or will no longer exist within a few short years. Those areas include: Business Specialists; Training Consultants; and MATSCO I&C Technicians.

J. Spare Parts

In Staff's direct case, Staff proposed to remove $20 million (total plant) from plant in service and to reclassify it, less one-half of the spare parts to be expensed in the first year of operations, as Materials and Supplies. The $20 million figure was based in large part upon the answer provided to Staff in a data request which stated that the value of spare parts included in construction work was $13,874,257. After the filing of Staff's direct case, the Company informed Staff that the $13.8 million amount was "wrong and [was] not available because [they were] unable to determine the price of the majority of the parts without a significant and costly effort."

Due to the Company's withdrawal of its support for the spare parts figure, Staff changed its position in its surrebuttal testimony filing. Staff now proposes a $20 million disallowance based upon the Company's inability to support a value for Wolf Creek spare parts inventory. Staff proposes this amount be disallowed until Company is able to provide the information necessary to make a determination of what the proper quantification of spare parts inventory is.

Staff admits that the $20 million amount is only an estimate of the value of the Company's spare parts inventory. That estimate relies upon an $18.3 million figure from the 1985 Wolf Creek forecast and statements from owners' representatives which led to the conclusion by Staff that additional spare parts were purchased with additional equipment and would not have been included in the forecast. Staff attempted to verify its estimate by applying an industry "rule of thumb" that the turnover to be expensed for spare parts was approximately 10 percent of the Company's inventory. Staff witness Cox testified that "rule of thumb" alone would lead to an approximate spare parts inventory of $45 million. Staff, therefore, maintains its $20 million estimate is conservative.

Staff contends it is essential to maintain adequate controls over spare parts inventory in order for management to determine the appropriate level of spare parts. According to Staff, cost knowledge is a measure of control. Lack of cost knowledge indicates lack of control and poor management performance. Staff contends Company could not have made a reasoned, prudent decision as to whether to purchase those inventory items initially without knowledge of their cost. Staff asserts proper cost control would have enabled the Company to have an approximate idea of the value of the spare parts that had been purchased and were on-site at the time of Staff's audit. Staff believes cost analyses should have been performed by the Company. Staff notes that Union Electric was able to approximate the value of its spare parts in its rate case.

Company argues that its spare parts program is similar to that of Union Electric. Since Union Electric's program was acceptable to the Staff, so should the Company's be. Company claims Union Electric relied upon the cost/benefit analysis of spare parts performed by the SNUPPS Joint Committee and that Company did also. It is Company's assertion that its inventory tracking system is exceptional. The Company points out that Union Electric was unable to cost out every item of spare parts inventory.

The Company contests the Staff's $20 million estimate. Company notes that Staff originally utilized a $20 million figure for reclassifying spare parts, which was based upon a $13.8 million figure supplied by Company and a $6 million figure arrived at by Staff. Company suggests it is ironic that Staff arrived at a similar figure for its disallowance based upon other data. It is the Company's position that there is no basis for the $20 million estimate because Staff witness Cox was unable to identify what portion of the $18.3 million from the 1985 forecast was used in construction of Wolf Creek and what portion was spare parts. There is also no basis for the additional $1.7 million amount, according to the Company. Company asserts Staff's estimate is overstated by approximately $9 million. As the basis for this figure, Company deducts the current Callaway Materials and Supplies account of $16 million from the total $25 million amount Staff assumes Company has expended for spare parts (the $20 million estimate plus $4.8 million already accounted for in Materials and Supplies). Company deducts that $9 million from Staff's $20 million estimate to arrive at an $11 million figure. In the event the Commission chooses to accept Staff's position, Company asserts an $11 million disallowance would be more appropriate than the $20 million estimate of Staff.

Although Staff's original proposal presented a method of accounting issue, Staff's present recommendation represents a proposed disallowance based upon failure to adequately track costs of spare parts. This failure on the part of the Company is evidenced by the withdrawal of its original estimate of the valuation of its spare parts and its failure to provide any type of substitute approximation.

The Company's argument that it was able to cost out the spare parts but had not done so due to the substantial expense involved is inadequate justification for its actions. It is true that an after-the-fact determination would be costly. That is why it is more appropriate for the Company to cost out its spares at time of purchase or as soon thereafter as possible.

The evidence indicated Union Electric was only able to cost out portions of its spare parts. In spite of this, Union Electric was able to provide, if not a complete valuation, at least an approximate valuation of its spare parts inventory to the Commission in its rate case. The problem here is that the Commission has no figure whatsoever from the Company to indicate the value of its spare parts inventory. The Company apparently deemed it unnecessary to maintain these types of records. The Commission finds this an unreasonable position. The Company must attempt to maintain adequate records of its inventory. It has not done so. The Commission finds the owners did not have a cost control system in place to assist them in determining the appropriate levels and associated values of spare parts. Without that control the Company is unable to support any level of spare parts as reasonable. It is not enough to simply rely upon recommendations of the SNUPPS Committee, without any further thought to cost of the spare parts. The rapidly escalating costs of constructing Wolf Creek made it imperative that adequate cost tracking be maintained by the owners. A failure to even attempt to do so, as has been demonstrated herein, represents management imprudence.

The Commission is of the opinion the method of accounting, i.e., classifying spare parts as M&S or plant in service, is not at issue here. The only issue pertains to the maintenance of appropriate cost control records. It is absolutely necessary to know the approximate value of the inventory no matter how it is determined to be booked.

The Commission is now faced with the difficulty of selecting an appropriate estimate of the level of spare parts at Wolf Creek. The Commission believes that both the Staff's and Company's estimates are flawed to a degree. That is a direct result of Company's failure to maintain adequate records. It is impossible to determine a precise dollar amount. The Commission finds that Staff's analysis is not as likely to reflect the Company's value of spare parts inventory as is the Callaway figure. Staff's estimate is based on the Company's forecast and an assumed additional amount. Since the record has repeatedly indicated the similarities between the design and construction of Wolf Creek and Callaway, the Commission finds that the most reasonable of the two estimates of spare parts value presented is the $11 million estimate of the Company. It is unfortunate the estimate must be based upon the unaudited Callaway figures presented by the Company, but unlike the Payroll issue discussed in Section IV.I.1. above, the Commission has no comparable figures from the audited UE budget upon which to base a different estimate. The Commission is therefore adopting Staff's underlying premise and the Company's proposed alternative amount resulting in a disallowance of $11 million as the best estimate of the valuation of the Company's spare parts inventory.

K. <u>Cash Working Capital (Wolf Creek)</u>

The majority of cash working capital issues were addressed in Phase III. The remaining issues to be decided are the proper treatment of nuclear fuel expense and the appropriate expense lags to use for Wolf Creek O&M expenses billed by KG&E to KCPL.

Staff includes one year of nuclear fuel expense in its lead/lag study because nuclear fuel is paid for quarterly as the fuel is actually burned. Staff proposes to include Wolf Creek Operation and Maintenance - Labor expenses billed by KG&E to KCPL in its lead/lag study line item Wolf Creek Operation and Maintenance - Payroll. The applicable expense lag would be 12.8 days. Staff proposes the application of a 37.71 day expense lag to its line item Cash Voucher - Other Operation and Maintenance expense. That line item includes Wolf Creek Operation and Maintenance - Other expenses.

The Company did not brief this issue but opposes the inclusion of nuclear fuel in the cash working capital study. Company believes the Staff's proposal is inconsistent with the treatment given non-nuclear fuel amortization and depreciation of utility plant. Company proposes to use KG&E's payroll and cash voucher expense lags of 14.68 and 18.63 days, respectively. Company makes its proposal because it expects to make cash advances to KG&E to offset the lag between direct payment of Wolf Creek expenses by KG&E and receipt of KCPL's payment for its share of the expenses.

The Commission believes Staff's treatment of nuclear fuel is appropriate. Staff's lead/lag study measures timing of the Company's quarterly cash payment.

Therefore, it does not matter whether the Company books its lease as a capital lease or an operating lease. The treatment of nuclear fuel differs from depreciation, which requires no current outlay of cash and is not included in a valid lead/lag study.

The Commission finds that the proper expense lag days are found in Staff's recommendation. Since there is no written operating agreement between KG&E and KCPL, there is no way to determine the actual period between KG&E incurring expenses and KCPL advancing or paying the cash to KG&E. Since the KG&E records are not Wolf Creek specific and have not been audited by the Commission Staff, the Commission prefers utilizing the periods recommended by Staff to those utilized by KG&E.

L. Depreciation

1. Wolf Creek Depreciation Rate

KCPL presented a depreciation study which results in a 3.53 percent depreciation accrual rate for Wolf Creek. However, KCPL proposes a 3.44 percent Wolf Creek depreciation rate which was approved by the Kansas Corporation Commission. Staff proposes a 2.6 percent depreciation accrual rate for Wolf Creek.

Staff and Company agree to an estimated retirement date of 39.5 years and a 10 percent negative net salvage value for future retirements. Staff and Company disagree as to the appropriateness of considering interim additions in the calculation of the depreciation rate. Staff and Company also disagree as to the appropriate level of interim retirements.

As part of the Company's depreciation study, Company witness Aikman studied 10 Westinghouse pressurized water reactors (PWR) to arrive at an interim capital addition rate of 2.8 percent and an interim retirement rate of .3 percent. As noted above, Staff opposes the inclusion of the interim addition rate in the calculation and proposes an interim retirement rate of .1 percent.

a. Interim Additions

Staff opposes the reflection of interim additions in depreciation rates on two grounds: (1) Section 393.135, RSMo 1978 prohibits the inclusion of the interim plant additions and depreciation rates and (2) the inclusion of interim plant additions in depreciation rates are inconsistent with accepted public utility depreciation practices.

Alternatively, even if the Commission adopted interim additions into the depreciation decalculation, Staff submitted evidence designed to show that the Company's calculation of interim additions is unreliable.

In Re: Union Electric Company, Case Nos. EO-85-17 and ER-85-160 (1985) the Commission was presented with identical evidence regarding depreciation rates for the Callaway Nuclear Plant.

Section 393.135, RSMo 1978, states as follows:

> Any charge made or demanded by an electrical corporation for service, or in connection therewith, which is based on the costs of construction in progress upon any existing or new facility of the electrical corporation, or any other cost associated with owning, operating, maintaining or financing any property before it is fully operational and used for service, is unjust and unreasonable, and is prohibited.

The Supreme Court has stated the purpose of Section 393.135 is "to make the utility wait until completion of the new construction before including the cost in rate base or otherwise recovering its expenditures." State ex rel. Union Electric Company v. Public Service Commission, 687 S.W.2d 162, 166 (Mo. banc, 1985). Since interim additions reflect such further construction, the Commission determines that future additions should not be reflected in the depreciation rate.

Aside from the question of whether Section 393.135 prohibits the inclusion of interim additions in depreciation rates, the Commission is of the opinion that the inclusion of interim additions is inconsistent with generally accepted notions of public utility depreciation accounting. The definition of depreciation contained in the Uniform System of Accounts and set forth in Exhibit 252, page 3 is as follows:

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

Depreciation is a method of measuring the consumption or exhaustion of an asset. The recovery of depreciation returns the cost of the investment associated with the asset to the investor as the asset wears out or loses service value. In the Commission's opinion future additions are not relevant to the above considerations and, therefore, should not be included in the calculation of the depreciation rate which is applied to existing plant in service.

b. Interim Retirement Rate

Staff proposes a .1 percent interim retirement rate based upon Staff witness Love's professional judgment.

Staff witness Rosenbaum performed an analysis of Aikman's study of 10 PWRs referenced above. The study was used to calculate the interim retirement rate as well as the interim addition rate. Rosenbaum testified that there are over 90 million ways to select 10 Westinghouse PWRs from a total of 33 Westinghouse PWRs. Thus, the selection of any 10 must be justified on engineering and cost grounds to be similar to Wolf Creek. No such justification or similarity was shown. Rosenbaum's analysis of the addition rate of the 10 PWRs revealed abnormalities with respect to the distribution of addition rates. Four of the units exhibited wide variances.

With respect to interim retirement rates, the 10 plants in the study range from 4 to 20 years in age. The interim retirement rates range from 0 to .792 percent. Although the study has been shown by Rosenbaum to be unreliable, the Commission notes that six of the plants in the study have interim retirement rates approximating .1 percent as used by the Staff. The Trojan plant which was included in the study, and which the Company asserts is similar to Wolf Creek for purposes of projecting future capital additions, has an interim retirement rate of .068 percent.

The Company mentions a DOE and two EEI studies which it alleges support a .3 percent interim retirement rates. However, no analysis of that data has been presented.

Considering all of the above, the Commission determines that Aikman's 10 PWR study is unreliable and that a .1 percent interim retirement rate as calculated by Staff should be used for purposes of this case. Accordingly, the Commission finds that the Wolf Creek depreciation accrual rate shall be 2.60 percent.

c. Primary Plant Accounting and Record Keeping

Staff proposes that KCPL be required to maintain its depreciation reserve by primary plant account. KCPL asserts that it intends to keep track of Wolf Creek investment by FERC subaccount and, therefore, no such order is necessary. The Commission determines that KCPL shall maintain its depreciation reserve by primary plant account as proposed by its Staff.

2. Non-Wolf Creek Depreciation

KCPL And Staff presented two depreciation studies for non-nuclear plant accounts. KCPL proposes a composite depreciation rate of 4.80 percent and Staff proposes a composite depreciation rate of 3.04 percent.

The Company's depreciation rates were last fixed by the Commission in Depreciation Authority Order No. 60.05, effective May 25, 1976. The current composite depreciation rate is 3.58 percent. Thus, Company proposes an increase to the current depreciation rate while Staff proposes a decrease to the current depreciation rate.

KCPL witness Liberda performed the Company's depreciation study. The life span method and the actuarial method were used.

The life span method was used for electric production plant accounts. Liberda utilized a computer life span model which was developed for each production plant site. Each model contains a historical record of past plant accounting activity as well as logic to simulate future activity. Liberda included the following factors in his life span analysis: (1) original investment; (2) plant addition; retirement, salvage and removal cost activity to the current time; (3) the expected useful life of the facility; (4) the projected retirements for the remaining useful life of the facility; (5) the projected salvage and removal costs associated with the projected retirement; (6) the replacement of projected retirements; (7) the decommissioning of the site at the end of its useful life; (8) effect inflation has on the previous factors; (9) the adequacy of historical depreciation rates.

Staff opposes the consideration of capital additions and fossil unit decommissioning costs.

The Commission has found against the inclusion of capital additions in depreciation rates for Wolf Creek depreciation rates and, therefore, the same reasoning applies when considering non-Wolf Creek depreciation rates.

The Company uses a negative net salvage value in the calculation of its proposed depreciation rates. This is because Company's estimated decommissioning cost of fossil plant exceeds the salvage value. The Company estimates decommissioning costs for Hawthorn 5, LaCygne 1 and LaCygne 2 and Iatan at approximately $136 million.

The Company has no specific plans for decommissioning or replacement of its fossil plants at retirement. A potential exists for the rehabilitation of its fossil units as is discussed in the accreditations section herein. No state or federal regulation exists which requires decommissioning funding for fossil plants as is the case with NRC requirements for nuclear plants. In addition, the fossil plant site can be used for subsequent power stations.

Based on the above considerations, the Commission determines that any decommissioning expenses associated with the future retirement of the Company's existing fossil plants are speculative. Since such costs are not known and measurable, the Commission finds that it is inappropriate to consider decommissioning costs for fossil units to determine net salvage value for the purpose of calculating depreciation rates.

Staff witness Love performed a depreciation study utilizing the actuarial and the life span method to arrive at the average life and the remaining life of the plant account investment.

The fully actuarial method utilizes survivor curves. The method requires a history of past additions and retirements by a vintage year obtained from Company records. From this history, survivor curves are constructed from successive historical retirement bands. Each of the retirement bands are matched to a family of actuarial life tables using a method of least squares in an attempt to establish a trend. Upon selection of the appropriate life and life table, average and remaining lives by vintage year are calculated and weighted with vintage surviving investment to arrive at a composite average and remaining life of the account. Staff applied the fully actuarial method to accounts consisting of large numbers of small units such as poles, meters and wire.

The life span method was applied to large structures and equipment such as buildings and electric power plants. These assets do not retire with such frequency to develop complete survivor curves which may be indicative of future life characteristics of the remaining units.

The life span method requires estimated dates of final retirement and surviving investment, estimated interim retirements expected over the remaining life and a history of past additions and interim retirements by vintage year.

From the history of additions and interim retirements, an interim retirement life table is constructed from actual experience and matched to a family of actuarial life tables. Using the average date of final retirement along with the smoothed interim retirement life table a reasonable prediction of the remaining life of each vintage of property investment is calculated. Additionally, from past historical data, the realized life to date can be calculated for each vintage.

Combining the realized life with the predicted remaining life of each vintage, properly weighted with each surviving investment the average life of the account investment is determined. By properly weighing each vintage surviving investment with the predicted remaining life, a composite remaining life is also determined.

In the Commission's opinion the Staff's method of estimating average lives and depreciation rates is appropriate. Staff has followed the method recognized as appropriate by the utility industry. Staff has followed a method authorized by the depreciation Subcommittee of the NARUC Committee on Depreciation and Valuation. In contrast, Company's study, aside from the defects associated with the inclusion of interim additions and decommissioning costs, utilizes a turnover method to arrive at an average life rather than actual data by vintage account. Staff's cites an EEI publication which addresses this method and questions its accuracy.

Having reviewed the Company's and Staff's depreciation studies, the Commission determines that Staff's study is superior to that of Company's and should, therefore, be adopted. However, the Commission is persuaded by Company's argument that Staff should have utilized a 35-year estimated useful life for LaCygne 1 and Montrose 2 for depreciation purposes. Although the Company's operating plan predicts limited operations for these units in an effort to address minimum load concerns, the Commission is not persuaded that Company's plant operations of those units will extend their useful lives by five additional years. Since Staff has accepted the Company's estimated useful lives of 35 years for the remaining coal-fired units, the Commission determines that 35-year useful lives should be utilized for the two units in question.

Accordingly, the Commission finds that the appropriate depreciation rate for the non-nuclear accounts shall be that calculated by Love's study adjusted to reflect a 35-year useful life for LaCygne 1 and Montrose 2. This calculation results in a composite depreciation rate of 3.48 percent.

V. Fuel Issues

Prior to the hearing, Staff and KCPL resolved the following issues: price of coal at Hawthorn Unit 5, gross inequity claim with Pittsburg and Midway Coal Company, and laws and regulation compliance cost adjustments. Both Company and Staff agreed upon a 90-day burn amount of coal, a 13-month average inventory quantity of limestone, and a dollar value of oil inventory.

A. Wolf Creek Equivalent Availability Factor

Equivalent availability is the percentage of time a plant is available at full capacity to generate power. To the extent the actual equivalent availability factor is less than the equivalent availability factor used to calculate fuel expense, the Company will undercollect fuel expense. The inverse is also true. Both Company and Staff have calculated a first year equivalent availability factor (EAF). The Staff proposes a 77.66 percent EAF. When used in KCPL's fuel budget model, that percentage becomes 76.9 percent. The lower percentage is due to extrapolation of outage rates from hours to weeks as required by the Company's fuel budget model. The Company proposes a 65 percent EAF.

To calculate its EAF, Company performed a least squares curve fit of historical plant capacity factors (CF) for Westinghouse plants greater than 1,000 MW using unadjusted data found in the United States Nuclear Regulatory Commission (NRC) publication NUREG-0020 (Gray Book). The Gray Book is a monthly publication put out by the NRC which contains statistical data on nuclear plants. The Gray Book indicates a 57 percent overall and 58 percent first year EAF for those Westinghouse units, including refueling outages. Accounting for refueling outages has the effect of lowering the EAF. The least squares curve fit yielded a first-cycle EAF of

55 percent. That EAF encompassed the first two years of commercial operations. Company then applied the 10 percent refueling outage to distribute the results between the two years. That resulted in a 65 percent and 45 percent EAF for the first and second years, respectively.

Staff performed a different type of analysis. Staff developed a percentage for full outages, both scheduled and forced, as well as partial outages to determine the EAF. A full outage is when the unit is completely out of service and no electricity is generated by it. The major difference between a scheduled and a forced outage is that the first is planned or can be delayed, the latter is unexpected and immediate. A partial outage results when the unit is not allowed to operate at full power due to repair, maintenance or economic necessity.

Since Wolf Creek had no operating history, Staff could not actually calculate the equivalent availability of the Wolf Creek plant. Instead, Staff estimated an EAF by considering data from similar plants. Staff witness Watkins calculated the full outage rate. He obtained outage data from the Gray Book on 21 units he deemed similar to Wolf Creek. Those units included all three and four loop pressurized water reactors with design electric ratings of at least 800 MW for which Westinghouse was the nuclear steam supplier. For those 21 units, the average planned scheduled outage rate was 16.7 percent, the average unplanned scheduled outage rate was 5.88 percent, and the average forced outage rate was 13.51 percent. Staff did not utilize the 16.7 percent scheduled outage rate in its EAF calculations.

Staff had to determine what it considered to be the appropriate period of time over which to determine the outage rates for the plants in its data base. Since Staff was attempting to calculate an EAF for the first year of Wolf Creek operations after the determination of its in-service status, Staff attempted to equate the Wolf Creek in-service criteria to the various plants studied. It is Staff's view that the appropriate study period is the first year of operations following demonstration of the unit's ability to reliably operate at full power. Staff only utilized data from the point in time that each plant was operating at an average of 90 percent of its design rating for at least one-half month. Mr. Watkins then examined various other factors, such as start-up testing and power level restrictions, before making a final selection of the in-service date.

Mr. Watkins made two adjustments to the outage hours reported in the Gray Book. In some cases, he adjusted the period hours in the first month of in-service operation to reflect the fact the unit had not operated at full power the entire month. That adjustment included deleting hours devoted to power ascension or testing prior to attaining full power. He also excluded hours which had been devoted to repairs or modifications which should not occur at Wolf Creek by reason of its more recent design, which incorporates design changes or modifications to prevent occurrences of those outages. That adjustment also excluded all reserve shutdown hours, since none should occur at Wolf Creek. Reserve shutdown is the removal of the unit from on-line operation for economic or similar reasons when operation could have been continued.

Unlike the Company, Staff asserts it did not use and does not recommend use of a refueling outage estimate, since there will be no refueling during the first 18 months after the plant's in-service date.

Staff witness Proctor calculated a partial outage rate of 4.60 percent. Dr. Proctor did not use the Gray Book as the basis of his information because the NRC does not gather data concerning partial outages. Instead, he utilized information from the North American Electric Reliability Council--Generating Availability Data System (NERC-GADS) which had been requested by Union Electric Company. NERC-GADS data is supplied voluntarily. It is not required as is the NRC data in the Gray Book. The units Dr. Proctor evaluated were 13 of the 21 units evaluated by Mr. Watkins. Dr. Proctor used group data, as individual data was not available.

Staff's study is challenged by Company for several reasons. The Company believes Staff should only have looked at data from Westinghouse units greater than

1,000 MW, as they are more similar in design and regulatory and operating environment. Only two of those units exceeded Staff's estimated EAF. It is contended that Staff has selectively used and interpreted the Gray Book data and, therefore, biased its study. Company points out that Staff did not compare its EAF to that of the plants in its data base. The Company asserts that Staff has ignored the effects of the learning curve set forth by Company which suggests that typical EAFs are slightly lower in the first cycles, presumably due to inexperience. It is the Company's assertion that Staff does, in fact, utilize a refueling outage estimate by deleting the estimated outage from its calculation. That assumed high refueling outage estimate makes Staff's EAF prediction far higher than it should be. The Company further asserts that Dr. Proctor's data is flawed due to the voluntary nature of its reporting.

The Staff contends that Company uses the words "capacity factor" and "equivalent availability factor" synonymously, while capacity factor, which includes economic off-loading and is dependent on the particular unit rating, will always be equal to or less than the EAF. Staff refutes Company's learning curve argument by asserting it is based on CFs, which tend to be inconsistent, rather than EAFs. Staff asserts much of the learning curve is caused, in part, by various plants in the data base being declared commercially operational prior to 100 percent power testing completion. Once Staff removes that inconsistent data, the learning curve was no longer apparent. Staff also attributes any learning curve to including refueling outages in the second year CF. Staff maintains that Company has arbitrarily chosen a 10 percent refueling rate and misapplied it to its data.

The Commission recognizes that no estimating technique is flawless, but believes Staff's analysis represents a more appropriate method of determining the estimated EAF for Wolf Creek than does the Company's analysis. The Commission finds that in order to estimate an EAF for Wolf Creek, it is necessary to utilize a first-year period similar to that which will be utilized at Wolf Creek; i.e.: beginning with a date comparable to this Commission's in-service date. This was accomplished by Staff. The Commission believes Company's use of the first full calendar year after commercial operation is inconsistent with this concept, and it does not necessarily reflect plants with an operational status similar to that of Wolf Creek. It does not prejudice the Company that the Staff reviewed Westinghouse units between 800 and 1,000 MW as well as over 1,000 MW. In fact, that overall review might tend to understate the resultant EAF, as the plants shown for all years between 800 and 1,000 MW had the lowest capacity factor of those reviewed. Neither is Staff's data flawed by the voluntary nature of the information submitted to NERC. No substantive evidence was presented which demonstrated the information was unreliable.

It is the Commission's belief that Staff's exclusion of various potential outages is proper. There is a plethora of evidence in this record which demonstrates that the SNUPPS units are "state of the art" and superior in design over other nuclear units. The Staff has excluded outages for Wolf Creek which should not occur due to the SNUPPS design, which has been modified to alleviate certain problems experienced at other plants. The Commission finds it is reasonable to do so and the Company's study is flawed in that those outages were not excluded from its data. The testimony indicated Staff did not believe those outages were caused by more than one reason and Company presented no evidence that they were.

The Company is comparing Staff's recommended EAF to other plants' CFs. Unlike those CFs, Staff's EAF does not include refueling. Hence, it appears higher in comparison. The Commission notes that even with no refueling, two of the plants were able to exceed Staff's recommended rate. The Commission is mindful of the fact that CFs are either equal to or lower than EAFs.

According to Company witness Hagan, of nine groups of sister plants in Staff's data base, built at or nearly at the same time, seven of the pairings had a higher first-year CF in the subsequent unit. The CFs for the nine subsequent units varied from 67 percent to 87 percent, with an overall average of 74 percent. An average of the seven subsequent units with a higher first-year CF demonstrates a 77.14 percent CF. Of the two units which decreased their CF, one decreased by only one percentage point and the other dropped from 78 percent to 72 percent.

The Commission finds that as a general rule, subsequent units perform at a higher CF, and therefore EAF, than do the first units. The Commission has previously found a 72.6 percent EAF to be reasonable for the Union Electric Callaway plant. Both Callaway and Wolf Creek are SNUPPS units and substantially identical in their design and construction and use of technology. Therefore, the Commission anticipates that Wolf Creek will have a higher EAF than Callaway.

The evidence in the record indicates that in its first seven months of operation, Callaway had actually achieved an 82.78 percent EAF, far greater than that estimated by the Commission. When that performance is considered in light of the prior evidence, including Staff's possibly understated EAF rate due to its utilization of all Westinghouse units above 800 MW, the Commission is of the opinion that Staff's estimate of 76.9 percent for Wolf Creek is a conservative one and should be achieved or exceeded by the Company. The Commission notes the testimony of Company witness Evans that in 1979 to 1980, the Company estimated the Wolf Creek EAF between 75 and 80 percent.

In spite of the fact that Callaway had not been operating a full year at the time of the hearing, the Commission finds that the performance of the Callaway plant is an excellent indicator of the performance of the "state of the art" SNUPPS units and supports the reasonableness of Staff's estimate. The Commission is not convinced by Company's argument to the contrary.

The Commission is not persuaded that a learning curve exists; however, if it does exist, it would merely bolster support for Staff's estimate when considered in conjunction with the first-year capacity factors, excluding refueling, of the 18 sister units in Staff's data base and the performance of the Callaway unit. It would demonstrate that those EAFs are lower than they will be in future cycles.

The Commission recognizes the fact that the Staff's estimate does not account for refuelings and presupposes an annual review to permit the calculation of an appropriate estimate for Wolf Creek refueling, maintenance and modification outage. The Commission does not believe an annual review is necessary. The Commission is of the opinion that Staff's estimate is conservative enough to allow for any decrease in the year of refueling without penalizing the Company.

B. Nuclear Fuel

Staff and Company agree that a first in, first out (FIFO) inventory method should be used to value Wolf Creek nuclear fuel. Staff and Company also recommend that credits received from Westinghouse under the terms of the uranium litigation settlement be allocated among the uranium amounts in the initial core and the first six reloads of nuclear fuel. Although Staff calculated the cost of nuclear fuel utilizing both a weighted average inventory method and a rapid amortization of Westinghouse credits, it does not actually recommend their use.

Hence, the only contested nuclear fuel issue is a determination of what period should be used to calculate the value of the fuel inventory in the reactor.

Staff has utilized a 13-month average of the balance of unburned nuclear fuel in the reactor and included that amount in rate base. Staff contends this type of calculation is appropriate because under the terms of the Company's fuel lease, it is required to make quarterly interest payments on the unburned portion of fuel in the reactor. Those payments are reflected in the cost of service through inclusion of nuclear fuel in the rate base and the fuel lease in the capital structure.

Staff asserts it is a known fact that the level of nuclear fuel in the reactor core will decrease throughout the first year of operation. Therefore, the use of any amount greater than Staff's average would overstate nuclear fuel inventory.

Company disagrees with Staff's methodology and recommends the Commission adopt a point-in-time concept instead. That concept would include in rate base the value of nuclear fuel in the reactor as of the date Wolf Creek is declared by the Commission to be in service. The Company agrees with Staff that the unamortized balance of nuclear fuel in the reactor will decline throughout the first year of commercial operation. However, the Company believes that Staff's 13-month average prejudices the plant investment included in rate base, since it does not consider changes to rate base such as property additions. The Company further maintains Staff's approach is inconsistent with both the use of end of test year plant in service levels for Company's other investments and the trended original cost less depreciation studies sponsored by Staff.

Contrary to the arguments put forth by Company, the Commission finds Staff's average to be a reasonable method of determining the value of fuel inventory in the reactor. The Commission finds that the point-in-time calculation recommended by the Company would overstate the nuclear fuel inventory, since the fuel would be at its highest level when the plant is declared in service. The Commission does not believe that the initial level adequately reflects the fact that the fuel in the reactor will steadily decline during the first year of operation.

The Commission does not believe Staff's method of valuing nuclear fuel is deficient because it differs from that utilized in Staff's trended original cost less depreciation studies. The methods measure two different things; i.e.: original cost versus fair value. The Commission finds it may not be possible to accurately calculate a 13-month average for all of the Company's plant in service; however, it appears that a reasonably accurate 13-month average can be calculated when utilizing a known quantity, such as the amount of nuclear fuel in the reactor core, which will decrease at a reasonably certain rate.

The Commission determines Staff's averaging method is consistent with the Commission's treatment of depreciation reserve in Section I.E.1. above. The Commission further finds that Staff's average does not prejudice the rate base calculations by not considering additions to rate base, because it avoided consideration of reductions as well as additions to net plant contained in rate base. Regarding consistency, the Commission notes the Company and Staff agreed upon 13 months average inventory of limestone at LaCygne, as well as the Company's use of a 13-month average for materials and supplies inventory in rate base.

Therefore, the Commission accepts Staff's 13-month average for nuclear fuel inventory and adopts both the FIFO inventory method of valuing nuclear fuel, and the recommended method of allocating Westinghouse credits among the initial core and the first six reloads, as reasonable.

C. Net Electric Capability

There is agreement between Company and Staff that the current net electric rating for Wolf Creek is 1,128 MW. The issue involves Staff's proposed offset of $296,579 (Missouri jurisdictional) to annual operating fuel expense based upon the difference between the 1,128 MW rating and the 1,150 MW capacity Staff believes was represented by the Company. Staff's offset represents displacement of fossil fuel produced power that would have occurred had Wolf Creek's net capability been the 1,150 MW so represented.

Staff asserts that Company has consistently utilized an 1,150 MW plant rating for Wolf Creek in prior regulatory proceedings before this Commission, yet the unit is licensed at only 1,128 MW. Staff contends that ratepayers are being forced to bear the full cost of Wolf Creek, and therefore should realize the full extent of its benefits. Staff points out that Wolf Creek is designed to accommodate a stretch rating of 1,180 MW. A stretch rating involves operation of a reactor at higher thermal power levels than originally licensed. This occurs through use of the safety design margin built into the plant. Higher level operation decreases fossil fuel generation and lowers system operating costs. Staff maintains it is important when forecasting Company's fuel cost that the proper capacity be apportioned to Wolf Creek versus other units so that nuclear fuel's lower cost is fully realized.

The Company admits it has, in the past, represented Wolf Creek to be an 1,150 MW plant. Company maintains that ratepayers have not been injured by that representation since rates have never reflected Wolf Creek investment. Although Staff used that rating in its evaluation of the Company's capacity planning study in a previous Commission case, the Staff was unable to identify any changes that would have occurred had it known of the actual rating. The Company points out it is licensed only to operate at 1,128 MW. The Company has not yet applied for a stretch rating and no Westinghouse four loop nuclear steam supply system of the type at Wolf Creek has been licensed for a stretch rating.

The Commission agrees that Company has represented the capacity of Wolf Creek to be 1,150 MW. The Commission does not believe it is necessary or appropriate to offset the Company's annual operating fuel expense for displacement of fossil fuel produced power. Therefore, the Commission finds it is reasonable to utilize the Company's actual 1,128 MW summer rating and 1,140 MW winter rating for fuel expense purposes.

D. <u>Forecasted Fuel</u>

A joint recommendation was submitted by Staff and Company which sets forth the incremental portion of fuel expense to be included in the rates established in this case. As part of the revenue requirement allowed by the joint recommendation, the Company is allowed an amount equal to the increased costs of coal and natural gas quantities required to generate electricity for the Company's Missouri retail use. The portion of rates which is based upon the additional revenue requirement associated with forecasted increases in the prices of coal and gas (unless it was excluded under paragraph 2 of the joint recommendation) will be subject to true-up (rate reduction) and refund. Staff believes that these provisions adequately protect the ratepayer.

Public Counsel opposes the joint recommendation and believes the Commission should deny any increment to the Company's fuel expense which is related to forecasted fuel. Public Counsel asserts the appropriate prices to be utilized for setting rates are the last known and measurable fuel expenses as trued up in this proceeding with other Company expenses. Public Counsel maintains the Commission should no longer engage in a forecasted fuel procedure which allows a utility to change its rates after the operation of law date with consideration given to only one of several factors affecting those rates; i.e.: fuel costs.

The purpose of allowing forecasted fuel prices is to give the Company the opportunity to recover additional fuel costs incurred by it to generate electricity to its retail customers. The Commission finds the allowance of forecasted fuel is an extraordinary remedy for highly inflationary times which protects the Company from paying costs which are beyond its control.

The Commission finds that low inflation rates and stabilizing fuel prices indicate there is no need for forecasted fuel in the instant case. The Commission believes that fuel prices at this time are equally as likely to decrease as increase. Staff witness Watkins agreed that with stabilizing fuel costs, the forecasted fuel procedure loses some of its value once a certain point is reached.

The Commission finds there is no imminent threat of increased fuel prices in today's market. The Commission notes the amount of fuel forecasted for Company this year is smaller than both the amount refunded last year and the amount forecasted last year. Although the decrease in the amount of fuel forecasted is due only in part to fuel expense, the Commission finds it to be an indication of the overall trend in fuel prices.

The Commission does not mean to infer by this decision that it will abandon forecasted fuel as a matter of regulatory policy. The Commission finds a fuel forecast is unnecessary based upon the facts of this case.

Although Public Counsel's recommendation presupposes a true-up proceeding, and none is to be had in the instant case, the Commission believes it is still more reasonable to consider last known and measurable fuel expenses than it is to forecast fuel prices in the instant case. Therefore, the Commission is hereby rejecting the joint recommendation of Staff and Company and adopting Public Counsel's recommendation.

E. Unit Availabilities and Heat Rates

Two varying approaches were used by Staff and Company in determining the unit availabilities and heat rates to be used in developing fuel expense. Staff, which has traditionally utilized historical averages, used the Company's System Power Operations Functional Plan (Functional Plan) as the basis for its calculation. For its Case A, Staff used the 1984 Functional Plan. For its Cases B and C, Staff used the 1985/1986 Functional Plan. The Functional Plan is a supporting tool for the budgets developed by KCPL. As it relates to fuel expense, it sets goals or targets for availability in the operation of its generating units. KCPL performed an analysis of what the units had experienced and identified areas of improvement to arrive at the availability percentages listed in the Functional Plan. The improvements KCPL identified are associated with a normal amount of dollar expenditures. Staff maintains the Functional Plan sets realistic goals and more closely resembles what the units will produce in the period covered than do historical averages. Staff asserts that use of the Functional Plan will allow ratepayers the benefits of the increased availabilities and heat rates they are paying for now, rather than after the next rate case.

The Company utilized historical averages of unit availabilities and heat rates, as has been the Commission's practice in the Company's last four rate cases. The Company disagrees with Staff's contention that the Functional Plan more accurately predicts the actual unit availabilities and heat rates that will be achieved. The Company contends the Functional Plan represents goals to be strived for, not necessarily what will be attained. KCPL maintains Staff's reason for utilizing the Functional Plan is the lower fuel expense resulting from its use.

The Commission finds that historical averages, rather than the Functional Plan, should be used when determining what fuel expenses and heat rates the Company will achieve. Although the Functional Plan is used as a budgeting tool, it appears that as it relates to unit availabilities and heat rates, it is more of an optimistic goal than a foregone conclusion. The Commission is concerned that use of the Functional Plan might understate the Company's fuel expense due to that factor. There was not enough evidence of the Functional Plan's superiority over the use of historical averages, and the Commission finds it is best to take the more conservative approach by using historical averages.

The Staff has, in the past, espoused the value of historical averages in determining unit availabilities and heat rates, in spite of the fact the Functional Plan has been available for several years. Although contending that the Functional Plan data is better in this instance, Staff has asserted its use in this case "should in no way signal to either the Company or the Commission that the Staff will utilize the results of the functional plan in future cases." The Commission is of the opinion that if the Staff is so uncertain of its method that it feels it must disclaim its future use, it probably should not be relied upon in this case.

F. Oil Burn

In determining the level of gas and oil burn at the Company's plants, Staff utilized historical averages of various durations. Staff projected an oil burn level of approximately 25,106 barrels at the Northeast combustion turbines (combustion turbines). The Company used historical averages at all plants except LaCygne 1, Montrose and its Northeast Station combustion turbines. Oil burn was estimated at those three units to reflect the anticipated change in their status when Wolf Creek becomes commercial. The oil burn level at the combustion turbines is estimated by Company to be 101,000 barrels.

The question here is whether the Company should be allowed additional expense for oil at its combustion turbines in order for those turbines to be ready to substitute power for Wolf Creek in the event it would be forced off line.

Staff maintains additional oil use is unnecessary. It is Staff's position that because of excess base load capacity available from existing units, Hawthorn 5 plus the availability of power from the interchange market should be adequate backup in the event Wolf Creek is forced off line.

The Company believes Staff's position is unrealistic and faults the Staff for using varying lengths of historical periods to develop its data. Under the North American Electric Reliability Council Control Performance Criteria, Wolf Creek power must be replaced within ten minutes after being forced off line. At that point, the Company proposes to utilize its combustion turbines, which start up quickly, to replace the lost energy until other units could be started. It takes eight to twelve hours to start and synchronize Hawthorn 5 if it is off line, and two to three hours to bring it to full load.

Interchange sales are not a good backup source, according to the Company, because it will be difficult to immediately replace the tremendous loss of power from Wolf Creek with market purchases. The Company maintains that other utilities are optimizing the commitment of their units and carrying less surplus generation on line for reserve. This occurrence makes the market extremely competitive. Even if it could temporarily replace the lost power on the interchange market, the Company contends such purchases would be more expensive than the use of its own combustion turbines.

Since the hearing, the Commission has received Late-filed Exhibit No. 606, which is the update to the Post-Wolf Creek Operating Study. The alterations made to the previous plan include making Hawthorn 5 available all months of the year. This differs from the previous plan, which operated Hawthorn on a seasonal but available basis to cover off-season scheduled and forced outages. Apparently Hawthorn 5 will now be on line year-round.

As far as interchange sales are concerned, the Commission once again notes the updated Post-Wolf Creek Operating Study, which discusses KCPL's potential for generating sales of its own energy in the interchange market. When so doing, the Company states that "[a]lthough there currently exists ample capacity throughout the Midwest which is expected to be available through the 1980's, KCPL appears to be in a favorable position in this 'buyers' market."

Wolf Creek is a very expansive plant, but one that has the benefit of SNUPPS "state of the art" design and technology. It is only reasonable to assume it will operate properly and efficiently. The Commission believes that if Wolf Creek is forced off line, it will not remain off line for any appreciable length of time. Looked at from that perspective, the Commission determines additional oil for the combustion turbines is unnecessary. Having Wolf Creek on line creates excess capacity in the Company's system. It is simply not reasonable to add additional fuel expense to provide backup support for Wolf Creek. The Commission finds that year-round availability of Hawthorn 5 and the existance of ample capacity in the interchange market will be sufficient backup in the event Wolf Creek is forced off line. Between the two, the Commission believes the lost power can be replaced in adequate time.

Although Staff's method of utilizing varying lengths of historical periods appears inconsistent, the Commission determines that no harm to the Company has been evidenced and finds that the historical data is still more reasonable than the projected estimate of the Company. Use of historical data is consistent with the type of study done by the Company and adopted by the Commission in Section V.E. above.

G. Interchange Sales

Interchange sales may be segmented into two components: one recovers fuel expense, the other constitutes markup or profit. The excess of the sales proceeds over fuel expense is credited against production O&M expense, which reduces the amount of O&M expense included in rates. Therefore, it is important to determine the amount the Company can expect to collect from energy sales above fuel expense.

Using a regression technique which considered load, generation capacity available and historical sales, the Company determined a level of interchange transactions. The Company priced interchange sales using normalized 1984 fuel costs and 1984 average markup. This resulted in a fuel expense component of $14.35 per megawatt hour and a markup component of $3.52 per megawatt hour.

For its Cases A and B, Staff utilized the 1984 level of kilowatt hours. The prices of the Cases A and B interchange sales come from calendar year 1984. For Case C the dollar level remains the same. Staff further based its analysis on assumptions regarding Company's future performance in the interchange market. No historical analysis was performed due to the Company's change in October 1983 from pricing interchange sales on a price-based average heat rate to an incremental heat rate price. That change in pricing tends to decrease the cost to generate interchange sales and would not properly reflect any increased sales volume anticipated.

Staff submits that Company should be able to achieve $21,845,485 in interchange sales. Of that amount, $14,488,000 will be attributable to fuel expense. That results in an approximate $7.4 million markup or profit. This compares to the Company's proposed markup of approximately $4.2 million. For comparative purposes, Staff's markup may be divided by its Case A level of sales, which was also used in Case C, to result in a markup of approximately $6.16 per megawatt hour. The Company's 1984 markup of $3.65 per megawatt hour is only 60 percent of that recommended by Staff.

The Company achieved a record level of interchange sales in 1984, yet achieved a markup of only $3.65 per megawatt hour. That record level appears due, in large part, to the Company's change in its method of pricing. Since that level of sales included a price based on the incremental heat rate, it is reasonable to expect the Company to maintain a sales level similar to that in the future. It is not reasonable to expect the Company to substantially exceed that level simply because the addition of Wolf Creek will decrease the cost of fuel further. This is true even though the Company's updated Post-Wolf Creek Operating Study states that the Company will be in a favorable position to sell interchange power. The fact remains that the interchange market is a highly competitive buyer's market. Price is not the only consideration. Even Staff was uncertain from whence the Company would derive its additional revenue increase, i.e., sales or markup. Staff merely felt certain that such a level would be attained.

The Company's figures may be slightly low, since its projected markup is less than that attained in 1984. This is presumably due to its partial reliance on average pricing data. However, the Commission believes it is better to be conservative in this instance than to be excessive. Therefore, the Commission is adopting the Company's position.

H. Rogers County Mine Closing

KCPL prematurely terminated the contract it had with Peabody Coal Company (Peabody) for coal from its Rogers County Mine on December 31, 1984. The contract would have expired by its own terms in 1996. Due to this early termination, KCPL must pay Rogers County Mine closing costs of approximately $8.7 million as they are incurred.

In July 1984 the Company requested bids from various coal companies to replace the tonnage it would lose as a result of the early termination of its coal contract. Twenty-seven companies responded. The lowest bid was given by Peabody for its Rochelle Mine. The contract was for the same tonnage volume, covered the same period of time and provided for the same plants as did the original contract with Peabody. Under the new contract, the coal supplied is less expensive than before.

The only issue here is the appropriate method to utilize in recovering these costs for ratemaking purposes. Staff believes the two transactions, terminating the one contract and entering into another, simply represent a renegotiation of the original contract, and therefore proposes to amortize the closing costs over the life of the replacement contract.

The Company maintains the transactions are unrelated and proposes to expense them as they are incurred. Company had a choice of paying as the costs were incurred or paying them over a ten-year period with interest. The Company chose the former option. Though informed of both options, Staff did not assert a preference. Approximately $7.9 million has already been paid. Should the Commission adopt Staff's approach, the Company requests that the unamortized portion be placed into rate base.

The early termination of the original coal contract created an unusual and nonrecurring expense. The Commission believes the appropriate ratemaking treatment of such an expense is amortization. If the entire amount of the closing costs was placed into annual expense, the Company would significantly overrecover its costs since the Commission is utilizing a phase-in period. The Commission is of the opinion amortization will not allow overrecovery, but will permit the Company complete recovery.

The relationship between the two contracts is not the determining factor. The original contract would have extended through 1996 and it is only reasonable that the costs associated with its early termination be recovered over that period of time. No evidence was put forth to support rate base inclusion of the unamortized portion of the costs and the Commission determines it is inappropriate to do so.

I. Hawthorn Units 1 Through 4

The Company does not reflect in its proposed fuel expense the retired units of Hawthorn Station. Staff takes the position the treatment of those units for fuel expense should be consistent with treatment of those plants for accreditation purposes.

Since the treatment of Hawthorn Units 1 through 4 for accreditation purposes is an excess capacity adjustment, the Commission does not anticipate that the units will be operational. Therefore, it is not necessary to reflect Hawthorn Units 1 through 4 in fuel expense.

VI. Allocations

A. General Plant

Staff's allocation factor used for general plant is derived by summing the production, transmission and distribution plant totals for both Missouri jurisdictional and adjusted base plant. The Missouri jurisdictional sum is divided by the adjusted base sum to arrive at the general plant allocation factor. The Company allocates general plant based on an analysis of the function and location of the equipment in each account.

Staff's method has been used in previous rate cases for this Company. The Company has failed to present any convincing argument in favor of a departure from Staff's general plant allocation methodology. Accordingly, the Commission determines that Staff's allocation methodology should be adopted for purposes of this case.

B. Materials and Supplies

The Company uses the production plant allocator of 65.59 percent to allocate materials and supplies between jurisdictions. Staff proposes a factor of 51.11 percent.

The Company contends that Staff's allocation is improper since it does not consider the Company's Front and Manchester warehouse.

Staff's allocation is based on the use of general materials and supplies at the Company's service centers. The allocation factor is derived by taking the ratio of materials and supplies located in Missouri to total materials and supplies. Company's books and records do not quantify the exact distribution of materials and supplies between Missouri and Kansas.

Since the Front and Manchester central warehouse materials and supplies will be sent to the service centers, Staff's method does indirectly consider the Front and Manchester inventory.

The Front and Manchester inventory of materials and supplies is also used to supply field crews working in Missouri and Kansas. The Commission is persuaded that materials and supplies are not tied to production plant operation. 52.44 percent of the Company's nonproduction CWIP is located in Missouri. These facts, along with the fact that sales in Kansas are growing faster than in Missouri, supports Staff's allocation as more reasonable than Company's.

Based on the foregoing, the Commission finds that Staff's materials and supplies allocation factor is reasonable and proper and should be adopted.

C. Grand Avenue Station

KCPL proposes to retire in place electric generating facilities at Grand Avenue Station, but continue to serve its steam customers with steam from the Grand Avenue Station. The Company proposes to operate Grand Avenue Station through 1990 and intends to develop a five-year plan to address the needs of the Company's steam customers.

Jackson County and the Federal Reserve Bank oppose any change in steam/electric allocations in this case and request the Commission to institute a general investigation concerning the future of steam service.

The Staff does not oppose the retirement of electric facilities at Grand Avenue Station, but is concerned about the appropriateness of the Company's program to install and operate electric boilers on steam customers' premises.

DOE and KPL Gas Service agree with Jackson County that the Commission should open a separate docket to explore all steam issues.

1. Electric Steam Allocation

Since there is no steam rate tariff pending before the Commission in this case, the issue of whether Grand Avenue Station should be retired from electric service has no effect on steam rates. However, future steam rates may be affected if the retirement of Grand Avenue Station from electric service, necessitates the allocation of 100 percent of Grand Avenue Station to steam customers.

In the Company's last rate case, Re: Kansas City Power & Light Company, 26 Mo. P.S.C (N.S.) 104 (1983), the Commission addressed the issue of electric and steam allocations of the Grand Avenue plant. The Staff had proposed that 70.29 percent of Grand Avenue Station be allocated to steam operations. The Commission rejected Staff's proposal and retained the existing allocation of 30.1 percent to steam service and 69.9 percent to electric service. In rejecting Staff's proposal the Commission recognized that Grand Avenue Station was used to generate 40 megawatts of electric service during two time periods and was used to furnish power to the downtown area when a transformer was lost from the system. As a further basis for rejecting Staff's proposal the Commission stated:

> Any change in allocation would temporarily result in the Company not receiving recognition for 100 percent of its plant. This fact is partly compounded by the Company's filing separate rate cases for electric and steam rates. In its next case the Company should file simultaneous revised tariffs for both electric and steam service.
>
> In its next case the Company should also submit its schedule for phasing the Grand Avenue Station out of electric service and phasing the allocation of the Grand Avenue Station to 100 percent steam service. Jackson County and Kansas City steam customers should be made aware by Company of this schedule at the earliest possible date in order that they may have the opportunity to gauge the impact on their heating costs and take appropriate action. Re: Kansas City Power and Light Co., 26 Mo. P.S.C. (N.S.) 104, 138 (1983)

The Company had planned to retire Grand Avenue Station Unit 7 from electric service in 1985, and Unit 9 in 1990. This was the Company's plan as late as

February, 1984. Unit 9 is rated at 40 megawatts. Unit 7, rated at 30 megawatts, was placed on inactive reserve status in 1982 and reaccredited for 1983 and 1984.

In response to the Commission's order, the Company formed a task force regarding the phase out of Grand Avenue Station. The task force concluded that: (1) Grand Avenue would not be essential to system operations after the addition of Wolf Creek; (2) transmission and distribution improvements could replace the downtown network support for Grand Avenue; (3) retirement of Grand Avenue from electric service would reduce O&M expenses and fuel expenses estimated at $1.4 million annually; (4) the improved fuel mix due to addition of Corn Products Corporation (CPC) to the steam load and a new one-year coal contract would result in estimated fuel cost reductions to steam customers of $3 million.

Based upon the above considerations, KCPL's System Expansion Alternatives Committee (SEAC) concluded that a 40 MVA 161/13 KV transformer should be installed at Grand Avenue West Substation by June, 1985, to transfer the downtown network support from Grand Avenue and upon commercial operation of Wolf Creek the electric facility at Grand Avenue should be retired.

Jackson County argues that the Company has shown no justification for retiring Grand Avenue from electric service and has ignored the Commission's order to phase the station out of electric service. Jackson County further contends that by retiring Grand Avenue from electric service KCPL is assuring the abandonment of steam service.

With respect to the allocation question, the Commission must reject Jackson County's arguments. KCPL steam users have been on notice since 1977 that Grand Avenue Station would be phased out of electric service. In the Company's 1977 general rate case, the Commission accepted the Company's allocation method recognizing that in the future Grand Avenue would be used exclusively for the production of steam heat. In that case both the steam intervenors, the Company and the Staff predicted steam responsibility for Grand Avenue at 37.2 percent in 1981.

See: 21 Mo. P.S.C. (N.S.) 543, 588 (1977). As noted above, the current steam responsibility at Grand Avenue is 30.1 percent.

With the addition of the Wolf Creek generating unit, Grand Avenue Station will be used exclusively for steam. The construction of the new transformer will provide more reliable backup service to the downtown loop since power is available instantaneously and can be supplied from any plant. Significant O&M savings associated with the addition of the new transformer and the retirement of Grand Avenue Station from electric service will occur. Although, the accreditation of Grand Avenue to electric service did enable the Company to avoid MoKan penalties in 1983, the Commission is persuaded that the accreditation of Grand Avenue for electric operations would not have been required if Hawthorn 3 and 4 had remained accredited.

The Commission determines that the retention of the current allocation is clearly inappropriate. The current allocation does not reflect the addition of CPC as a large industrial steam user. In 1984 CPC more than doubled KCPL's steam revenues. Although CPC sold its plant to National Starch effective January, 1986, KCPL has negotiated a new agreement with National Starch. KCPL expects the National Starch steam usage to be lower than that of CPC. Nevertheless, National Starch's usage is not reflected in the current allocation.

A gradual phase out may have been appropriate if steam users were experiencing rate increases on an annual basis as has been the experience with electric users. The Commission notes that the last tariff increase for steam service became effective June 4, 1982, in Case No. HR-82-67, Re: Kansas City Power & Light Company. Thus, KCPL's steam users have not experienced increased rates in almost four years. In addition, the Company has committed not to increase steam rates prior to 1987, but thereafter steam rates may be filed.

In light of the fact that Grand Avenue is not needed for economic or reliability reasons; that steam users have been on notice of the future 100 percent allocation of Grand Avenue to steam service since 1977; that steam users have had no steam rate increase since 1982; that the Company has committed to no steam tariff increase filing until 1987; and the fact that electric users are being burdened with the largest electric rate base addition in KCPL's history, the Commission finds that it would be improper and inequitable to continue to allocate Grand Avenue costs to electric service.

2. Steam Service

The Company has notified its steam customers that contingent upon a five-year interruptible steam heat agreement with National Starch, the Company is committed to operate the Grand Avenue steam facility through 1990.

KCPL has begun a test project where the Company will install and own electric boilers as a substitute steam source on the premises of certain steam heat customers. The Company will continue to provide steam heat at the applicable steam heat rate for such customers. The Company intends to use the results of this test project to develop a five-year program to convert the steam heat load to on-site production.

The Company intends to develop a tentative five-year conversion plan to eliminate its low pressure steam distribution system through the use of on-site electric boilers and minimize its high pressure steam distribution system through a central electrode boiler, by on site installation or various combinations with electric operation. The Company intends to present the tentative plan to its steam heat customers in March, 1986, for their review and comment.

The evidence in this record suggests that KCPL is seriously considering abandoning steam service after 1990.

As pointed out by Jackson County, KPL Gas Service, and Staff, the Company's on-site electric boiler test program raises questions regarding possible (1) violation of the Commission's promotional practices Rule 4 CSR 240-14; (2) whether the service is electric rather than steam service; (3) and whether Grand Avenue steam users are subsidizing electric boiler steam users.

Staff recommends that the Company be directed to furnish a documented cost comparison study showing the installed rate base costs and O&M expenses of the electric boiler are lower than continued O&M of existing fully depreciated steam plant and lines. Staff also requests that KCPL show existing steam rates will earn the required rate of return under the program.

In addition, Staff recommends that if electric boilers are authorized Company should install meters at each on-site electric boiler in order to determine steam jurisdiction contribution to the electric demand allocator.

Based upon the above considerations, the Commission finds that a docket should be opened for the purpose of investigating the future of steam service, the appropriateness of the on-site boiler program and the proper pricing of steam service.

Based upon KCPL's commitment to no increase in steam rates prior to 1987, the Commission determines that the Company shall not file steam tariffs until 1987.

The Commission finds that meters shall be installed on all on-site boilers under the Company's test program as recommended by the Staff.

With respect to the question as to whether the Company should cease its on-site boiler program, the Commission determines that the Company should impose a moratorium until the issue can be addressed in the investigatory docket.

Since the steam docket will address the pricing of steam service, the Commission notes that depending on the status of the Company's steam plant and steam service, the Commission is not committed to a 100 percent allocation of embedded plant to steam service. The Commission is willing to explore alternate pricing strategies.

Based on the foregoing, the Commission determines that KCPL shall file its steam service plan on or before May 1, 1986, in Docket No. HO-86-139.

VII. Fair Value Rate Base

The Commission concludes that KCPL's fair value rate base shall be the trended original cost less depreciation of KCPL's Missouri jurisdictional electric plant, which is $1,126,914,700 excluding Wolf Creek. Adding the appropriate original cost of the Missouri jurisdictional portion of KCPL's investment in Wolf Creek of $798,846,000 results in a fair value rate base of $1,925,760,700.

VIII. Revenue Requirement

Based on the findings and conclusions herein, KCPL's total revenue requirement is approximately $437,980,083, requiring increased revenues of approximately $78,245,000 which will be phased into rates according to the phase-in plan adopted herein. The cumulative increased revenues including carrying charges at the end of the 7-year phase-in period is $120,115,000.

IX. Phase-in Proposals

KCPL proposes a four-year phase-in of the Wolf Creek revenue requirement. The annual percentage increases would be as follows: first year, 26 percent; second year, 14 percent; third year, 8 percent; fourth year, 5.4 percent; fifth year, no increase or decrease. The phase-in is designed to recover Company's proposed 52 percent revenue increase plus the carrying costs on the deferred revenue requirement over a five-year period.

Under the Company's proposal, the phase-in rate increases would be accomplished by separate rate schedules setting forth the annual rates with the timing of each increase in rates under the phase-in identified in the schedules. Each increase would automatically take effect when indicated in each rate schedule.

As part of its phase-in proposal, KCPL committed to a moratorium on filing for rate increases to be effective for a four-year period, assuming the Commission includes KCPL's total investment in Wolf Creek rate base on a timely basis following its commercial operation.

Staff proposes to phase into rates the Wolf Creek revenue requirement based on the capacity requirement needed to meet a levelized reserve margin.

Staff's phase-in is accomplished by deferring the total equity return on Wolf Creek. Any additional incremental Wolf Creek revenue requirement in excess of the total equity return on Wolf Creek is deferred by accelerating the basis for amortization of the deferred income taxes. Under Staff's proposal the carrying costs related to the deferral of the equity return on Wolf Creek are calculated at the return on equity. Staff takes no position as to whether deferred earnings and carrying costs should be placed into rate base or expensed over a specified period.

Staff proposes that the length of the phase-in period not be determined in this case. Instead, the percentage of Wolf Creek deferred equity return and carrying costs included in each year should be determined on an annual basis. Annual phase-in adjustments would depend on the actual growth in KCPL's peak demand and additional Wolf Creek capacity required to meet the Company's levelized reserve margin.

Staff's proposal does not recognize the 5.5 percent of the plant representing the difference between a 47 and a 41.5 percent ownership interest in Wolf Creek. The difference between a 47 and a 41.5 percent ownership interest under Staff's proposal is treated as the last portion of the plant's revenue requirement to be phased into rates.

Staff's phase-in proposal recommends that operational savings associated with Wolf Creek capacity in excess of the levelized reserve margin should be used to offset the carrying costs related to the deferrals. The source of the operational savings is KCPL's long-range operating study.

Public Counsel proposes that any phase-in adopted by the Commission should be limited to an increase in rates in any one year to no more than 15 percent. Assuming the Commission's acceptance of Public Counsel's issues regarding imprudence and economic excess capacity, Public Counsel proposes a 15 percent increase in the first year and a 10 percent increase in the second year.

Public Counsel further contends that any phase-in adopted by the Commission should allow for review of any phase-in tariffs to go into effect in future years prior to the effective dates of those tariffs. Public Counsel contends that a failure to provide such a review is illegal and beyond the statutory authority of the Commission.

DOE proposes that profits from off system sales above KCPL's adjusted test year levels be used prospectively as a reduction to deferrals associated with any possible phase-in plan adopted in this proceeding.

Industrial Intervenors, Monsanto, et al., recommend that the five-year phase-in proposed by KCPL be lengthened to a fixed period of 20 years so that annual increases would be as follows: year one, 12 percent; years two through five, 8 percent; years six and seven, 5 percent; years eight through ten, 6 percent; years eleven through twenty, no increase.

To the extent revenue levels are determined to decrease without Wolf Creek, Industrial Intervenors recommend that the reduced rates should be the starting point for any Wolf Creek phase-in.

The Industrials recommend that rate increases should not be automatic and, therefore, the phase-in plan would provide for a review of cost of service every two years. Finally, Industrials recommend that the deferred revenues be measured by KCPL's overall rate of return rather than by its cost of equity.

The City of Kansas City takes the position that in order to avoid an adverse economic impact on the citizens of Kansas City in terms of jobs and real disposal income, a longer phase-in than that recommended by Company is appropriate.

The State of Missouri recommends a six-year phase-in comprised of a 12 percent first year increase, an 8 percent second year increase, and equal percentages increases for the remaining years so long as none of the increases exceed 8 percent.

Jackson County proposes no rate increase and, therefore, no phase-in, since, Jackson County takes the position that there is no need for Wolf Creek capacity.

The Commission has carefully reviewed the evidence and the arguments respecting the various phase-in proposals and finds that a phase-in plan shall be adopted as follows:

1. The phase-in shall be over a period of seven years.

2. The increase in year one shall be 7 percent followed by an increase of 5 percent in year two. The increases in years three, four, five, six and seven shall be 3.49 percent.

3. The phase-in shall be accomplished under Staff's general phase-in approach as shown in Exhibit 625, pages 15 and 16, Appendix GTA-PISC7.7.

4. The carrying costs on the deferred revenues under the phase-in plan shall be calculated at the overall rate of return.

5. All deferrals and carrying costs shall be expensed over the phase-in period.

6. Tariff sheets implementing the phase-in will automatically take effect in succeeding years unless suspended by the Commission for good cause shown.

The Commission believes that a fixed phase-in is appropriate to give assurance to the financial community that the deferrals and carrying costs associated with the phase-in plan will be recovered in the future years of the phase-in. A fixed phase-in also allows ratepayers to plan their budgets and consumption patterns based upon a reasonable projection of fuel increases over the phase-in period. Finally, the Commission believes that the Company will have an incentive based upon the fixed phase-in to postpone rate requests.

Having determined the appropriate Wolf Creek investment for ratemaking purposes and having adjusted for excess capacity on the Company's system, the Commission has utilized Staff's phase-in model with certain modifications. In general, the Commission believes that Staff witness Proctor's levelized reserve margin is an appropriate concept to be utilized for the phase-in of Wolf Creek.

The levelized reserve margin concept is revenue neutral and does not deal with excess capacity in the traditional sense. It recognizes "excess reserves" only in the sense that size restrictions on plant additions result in the existence of reserve margin above that required if no size restrictions exist. Given the minimum reserve margin, the levelized reserve margin is the point at which the reserve margin is equal to the long-run average reserve and the utility is neither short nor long on reserve capacity.

Given the accredited capacity for each unit, the peak load forecast, the minimum reserve margin, the phase-in model calculates that portion of Wolf Creek which is needed to meet the levelized reserve margin.

Staff's proposed phase-in assumed a first year decrease associated with the non-Wolf Creek revenue requirement decrease calculated in Staff's Case B. The Case B decrease affects the phase-in of Wolf Creek since the phase-in model incorporates the price elasticities contained in the Company's peak load forecast. Therefore, assuming a first year decrease, results in Wolf Creek being needed earlier than would be the case if a first-year increase were assumed of approximately 16.2 percent.

Although Case B does justify a non-Wolf Creek revenue decrease, the Commission believes a first-year decrease followed by a Wolf Creek related increase results in a poor price signal for electricity users. Thus, the Commission determines that the Case B revenue decrease should be offset against the Wolf Creek revenue increase and the net amount should be phased into rates.

Netting the Case B decrease against the Wolf Creek related increase and utilizing Staff's phase-in model, assuming the accreditation, and reserve margin found reasonable in this case results in a six-year or a seven-year phase-in. The six-year phase-in shows a 4.71 percent increase in the first year followed by a 5.66 percent increase in each succeeding year. The seven-year phase-in produces a 4.71 percent increase in the first year and a 4.75 percent increase in each succeeding year.

The Commission requested additional phase-in scenarios assuming a 7 percent first year increase followed by a 5 percent second year increase and a 6 percent first year increase followed by a 5 percent second year increase.

Having reviewed the phase-in schedules supplied by the Staff in response to the Commission's requests, the Commission determines that a seven-year phase-in assuming the 7 percent first year increase followed by a 5 percent second year increase with a 3.49 percent increase in each succeeding year is appropriate. This phase-in plan would require a 12.43 percent reduction in the eighth year.

In the Commission's opinion a 7 percent first year increase should not result in an undue hardship to KCPL customers. Greater increases in the first years of the phase-in result in lower amounts of deferrals and a lower overall increase at the end of the phase-in period than would be the case under smaller percentage increases in the first years of the phase-in.

The Commission determines that the carrying costs on the deferrals under the phase-in should be calculated at the overall rate of return rather than at the return on equity. The Commission is persuaded by the Industrial Intervenors' argument that the deferred revenues should be financed with the same combination of debt and equity used to finance all of KCPL's capital expenditures. The Commission has determined the appropriate overall cost of capital in this case is 11.75 percent. Therefore, the Commission finds that carrying costs of 11.75 percent will produce a just and reasonable adjustment to reflect the fact that recovery of a part of the revenue requirement found appropriate is deferred to future years.

Finally, the Commission determines that it is appropriate to offset the carrying costs related to the deferrals by the operating savings set forth in KCPL's long-range operating study.

The Company contends that its updated operating study reduces the projected savings. In addition, the Company claims that the majority of the savings have already occurred and are, therefore, included in Staff's Case B. The Company argues that including these savings in the phase-in constitutes double counting.

The operating study projects approximately $3.4 million in labor savings and approximately $7.7 million in non-labor savings. The Commission notes that the Company accepted DOE's $6.8 million adjustment to the 1984 test year to reflect a future reduction in non-labor non-fuel non-Wolf Creek generating requirements. Thus, the Company is unable to successfully argue that these savings are included in Case B which is based on the 1984 test year.

The Company contends that most of the labor savings have occurred since the actual manpower at year-end 1984 was at 1046 employees, where the operating plan projected a manpower level of 1042 employees.

T... Commission determines that the Company has not shown that these labor savings will not occur. The record reflects that the Company consistently overbudgets labor O&M and that the Company contracted labor in 1984 to supplement the work force.

Finally, the Commission determines that DOE's proposal to use off-system profits to reduce deferrals on a prospective basis should be rejected. Since the Commission has adopted a fixed phase-in such an adjustment would be impracticable.

The Commission determines that the phase-in plan adopted herein meets the requirements of Missouri law set forth in Section 393.155, RSMo (Cum. Supp. 1984), which is set forth below:

> If, after hearing, the commission determines that any electrical corporation should be allowed a total increase in revenue that is primarily due to an unusually large increase in the corporation's rate base, the commission, in its discretion, need not allow the full amount of such increase to take effect at one time, but may instead phase in such increase over a reasonable number of years. Any such phase-in shall allow the electrical corporation to recover the revenue which would have been allowed in the absence of a phase-in and shall make a just and reasonable adjustment thereto to reflect the fact that recovery of a part of such revenue is deferred to future years. In order to implement the phase-in the Commission may, in its discretion, approve tariff schedules which will take effect from time to time after the phase-in is initially approved.

In compliance with the statute, the Commission has allowed a return on the deferred revenues which results in a total revenue increase over the period of the phase-in of $120,115,000.

X. Financial Integrity

Staff, Company, Public Counsel, DOE and the City of Kansas City presented testimony analyzing the financial impact on the Company of the various phase-in proposals. The Commission has carefully considered these analyses in arriving at its phase-in determination.

Company witness Beaudoin analyzed Staff's then current phase-in proposal which presumed an eight-year phase-in with no increase in the first year and increases in the succeeding years in the 6.5 percent range. The analysis shows funds generated internally in the amount of $45.1 million in 1986, increasing to $119.4 million in 1990. Bond indenture coverage for 1986 is 2.0 increasing to 3.6 in 1990. Deferred charges as a percentage of earnings is 115 percent in 1986 decreasing to 50 percent in 1990. Return on equity is 9 percent in 1986 decreasing to 6.9 percent in 1990.

Staff witness Skirpan developed estimates of the Company's financial condition under the following combinations of scenarios: 1) a 10 percent, 20 percent, 30 percent and 70 percent permanent disallowance of Wolf Creek investment; 2) a phase-in based on KCPL's phase-in proposal and alternatively a phase-in showing no increases through 1989; and 3) a write-off of the disallowed portion of Wolf Creek.

Skirpan also developed estimates for KCPL over the 1985 to 1989 period on the basis of Staff's then current phase-in proposal assuming 1) a permanent Wolf Creek disallowance of approximately 14.6 percent of the cost of Wolf Creek sought to be recovered in this proceeding; 2) a temporary disallowance of 11.7 percent of Wolf Creek costs comprising the Staff's ownership share adjustment; 3) a non-Wolf Creek revenue requirement decrease of approximately 16 percent; 4) a 9-year phase-in of the Wolf Creek incremental revenue requirement of approximately 46 percent; and 5) no write-off of disallowed portions of the Wolf Creek investment.

A comparison of Staff's estimate of some of Company's financial indicators under the scenario assuming a 30 percent disallowance and no increase through 1989 and the scenario assuming Staff's 9-year phase-in is set forth below:

Financial Indicators	30% 1986	Phase-In 1986	30% 1987	Phase-In 1987	30% 1988	Phase-In 1988	30% 1989	Phase-In 1989
Pre-Tax Interest Coverage (Incl. AFUDC & EQPH)	2.26X	2.05X	2.8X	2.53X	3.15X	2.92X	3.40X	3.34X
Debt Leverage	63.8%	52.1%	61.8%	50.8%	63.6%	52.8%	61.3%	50.8%
Net Cash Flow/Capital Outlays	50.22%	61.3%	39.2%	61.5%	27.0%	79.9%	23.1%	111.0%
Cash Flow Per Share	$ 5.11	$ 5.48	$ 4.86	$ 5.55	$ 4.54	$ 5.92	$ 4.56	$ 6.86
Net Cash Flow Per Share	$ 1.69	$ 2.07	$ 1.21	$ 1.90	$ .71	$ 2.10	$ .61	$ 2.91
Book Value Per Share	$14.60	$27.48	$15.71	$27.46	$ 17.11	$27.44	$ 18.96	$ 27.63

Company's analysis of Staff's phase-in proposal does not match revenues and expenses, since it assumes some Company proposed expenses in this rate case and Staff's revenues. Therefore, Company's analysis tends to understate interest coverage and return on equity.

Skirpan's analysis shows that a 30 percent disallowance coupled with no recovery through 1989, would not severely undermine KCPL's financial integrity, if the Company were to write-off all permanent disallowances. The Commission notes that Skirpan's 30 percent-no recovery scenario goes well beyond the phase-in adopted in this case.

Staff witness Ileo testified that the market has already accounted for Wolf Creek disallowance in the 20 percent range. The disallowance on Wolf Creek investment adopted herein amounts to approximately 14 percent.

In the Commission's opinion the phase-in adopted herein will result in stronger financial results than shown in Skirpan's analysis of Staff's phase-in. This is because the phase-in adopted herein is two years shorter than the 9-year phase-in assumed in Staff's proposal. In addition, the phase-in adopted herein results in greater cumulative rate increases in the first three years of the phase-in; 7 percent, 5 percent and 3.4 percent; contrasted to a 2 percent reduction followed by two years of increases in the 6.9 percent range. The higher increases in the early years of the phase-in adopted herein will improve the Company's cash flow in the early years.

The return on equity shown in Skirpan's analysis of Staff's 9-year phase-in is 10.2 percent rising to 13.3 percent by 1989. These figures are likely to be understated since investors are likely to take into account the Commission's permanent disallowance of Wolf Creek costs even though KCPL does not take a write-off of these amounts.

The Commission determines that upon the implementation of the phase-in adopted herein, the Company will be able to improve its cash flow, and maintain adequate interest coverages. The return on equity level may be somewhat reduced, but this is a proper result of the Commission's findings regarding disallowances of imprudently incurred costs and excess capacity.

Based on the foregoing, the Commission determines that KCPL should be able to attract capital and preserve its financial integrity during the phase-in.

Conclusions

The Missouri Public Service Commission has arrived at the following conclusions:

Kansas City Power & Light Company is a public utility subject to the jurisdiction of this Commission pursuant to Chapters 386 and 393, RSMo 1978.

Kansas City Power & Light Company's tariffs, which are the subject matter of this proceeding, were suspended pursuant to authority vested in this Commission by Section 393.150, RSMo 1978, and the burden of proof to show that the increased rates are just and reasonable is upon KCPL.

The Commission may consider all facts which in its judgment have any bearing upon the proper determination of the setting of fair and reasonable rates.

The Commission may accept a stipulation and agreement in disposition of the issues of a rate proceeding when it appears that the proposed settlement is fair and equitable to all concerned.

The Commission may allow a phase-in of an increase in revenue that is primarily due to an unusually large increase in a corporation's rate base. The Commission may in its discretion approve tariff schedules which will take effect from time to time if the phase-in is approved.

Based on the revenue requirement found reasonable herein, the Commission concludes that Kansas City Power & Light Company shall be allowed to file revised tariffs designed to increase revenues exclusive of gross receipts and franchise taxes by approximately $78,245,000 on an annual basis.

The proposed tariffs shall reflect a 7-year phase-in plan as established in the findings and conclusions herein, as ordered below.

The tariffs authorized herein shall reflect the rate design found reasonable herein.

On June 7, 1985, Jackson County, Missouri, filed a motion to dismiss Case No. ER-85-128 on the ground that the proposed tariffs filed by KCPL on November 26, 1984, were filed with a proposed effective date which was prior to the Wolf Creek Generating Facility being fully operational and used for service. Jackson County reasoned that the filing was therefore in violation of Section 393.135, R.S.Mo. Supp. 1985, and the case should be dismissed.

The Commission finds that the proposed tariffs filed in Case No. ER-85-128 were withdrawn on October 15, 1985. That case was dismissed on November 6, 1985, and incorporated by reference into Case No. EO-85-185. The Wolf Creek Generating Facility satisfied the in-service criteria of the Commission at 1:15 a.m. on September 3, 1985. Since the Wolf Creek Generating Facility is fully operational and used for service, the Commission deems the motion of Jackson County, Missouri, moot. The motion is therefore denied.

It is, therefore,

ORDERED: 1. That pursuant to the findings and conclusions in this Report and Order the proposed revised tariffs filed by Kansas City Power & Light Company of Kansas City, Missouri, in this case be, and the same are, hereby disapproved and Kansas City Power & Light Company is authorized to file in lieu thereof, for approval of this Commission, tariffs designed to increase gross revenues exclusive of gross receipts and franchise taxes reflecting a one-time increase of approximately $78,245,000 on an annual basis.

ORDERED: 2. That Kansas City Power & Light Company is directed to file tariffs reflecting the phase-in plan authorized herein which will become effective automatically in each year of the phase-in unless suspended by the Commission for good cause shown or unless the Company files tariffs requesting increased rates. This results in a total increase of $120,115,000 over the phase-in period.

ORDERED: 3. That the tariffs authorized herein shall reflect an increase of approximately seven percent (7%) or $25,172,000 for 1986.

ORDERED: 4. That the tariffs authorized herein shall reflect the rate design found reasonable in this Report and Order.

ORDERED: 5. That the tariffs to be filed pursuant to this Report and Order under the first year of the phase-in shall become effective for service rendered on and after May 5, 1986.

ORDERED: 6. That the subsequent tariffs approved in accordance with the phase-in plan shall become effective in each subsequent year on May 5. The tariffs reflecting increases under the phase-in plan for years two through seven shall be filed on or before June 5, 1986. The automatic phase-in tariffs shall include a tariff for the eighth year reflecting a 12.43 percent decrease.

ORDERED: 7. That late-filed exhibits 606 through 626 described in Appendix C, attached hereto, be, and they are, hereby received; also, late-filed exhibits 604 and 139 are received.

ORDERED: 8. Any objections not heretofore ruled upon or overruled or any outstanding motions are denied.

ORDERED: 9. That on or before September 29, 1986, Kansas City Power & Light Company shall provide to the Staff and the Public Counsel an updated operating plan showing the actual operations of its units for the first twelve months after Wolf Creek is in service, and the Company's operating plan for the succeeding twelve months.

ORDERED: 10. That Kansas City Power & Light Company shall maintain electronic dispatchers' logs.

ORDERED: 11. That Kansas City Power & Light Company shall provide Staff with the information regarding Bechtel design deficiencies as set forth in this Report And Order.

ORDERED: 12. That Kansas City Power & Light Company is hereby directed to comply with the Commission's procedures for decommissioning as set forth herein.

ORDERED: 13. That Kansas City Power & Light Company shall maintain its depreciation reserves by primary plant account.

ORDERED: 14. That Kansas City Power & Light Company shall install meters on its on-site boilers as set forth herein.

ORDERED: 15. That Kansas City Power & Light Company shall impose a moratorium on its on-site boiler program pending the resolution of Case No. HO-86-139.

ORDERED: 16. That the motion to dismiss Case No. ER-85-128 filed by Jackson County, Missouri, on June 7, 1985, be, and hereby is, denied.

ORDERED: 17. That this Report And Order shall become effective on the 5th day of May, 1986.

BY THE COMMISSION

Harvey G. Hubbs

Harvey G. Hubbs
Secretary

(S E A L)

Steinmeier, Chm., Musgrave, Mueller,
Hendren and Fischer, CC., Concur and
certify compliance with the provisions
of Section 536.080, R.S.Mo. 1978.

Dated at Jefferson City, Missouri,
on this 23rd day of April, 1986.

CASE NO. EO85-185

WDS
Chairman

C. M
Commissioner

A. G. M
Commissioner

CBH
Commissioner

JM
Commissioner

3/1584c

STATE OF MISSOURI

OFFICE OF THE PUBLIC SERVICE COMMISSION

I have compared the preceding copy with the original on file in this office and I do hereby certify the same to be a true copy therefrom and the whole thereof.

WITNESS my hand and seal of the Public Service Commission, at Jefferson City, this 23rd day of April 1986.

Harvey G. Hubbs

Harvey G. Hubbs
Secretary