BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA, AN OKLAHOMA CORPORATION, FOR AN ADJUSTMENT IN ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA.	)	CAUSE NO. 27068 ORDER NO. 206560

HEARINGS: October 31, 1980 (Cause No. 26959) Hearing on Interim Rate Increase, before the Commission, en banc;
July 23, 1981 Hearing on Additional Request for Interim Relief, before the Commission, en banc;
September 1, 1981 Pre-hearing Conference;
September 14 through November 10, 1981 Hearing on the Merits before the Commission, en banc.

APPEARANCES: See Official Record.

BY THE COMMISSION:

Public Service Company of Oklahoma (hereinafter referred to as P.S.O. or Applicant) filed its Application seeking a permanent rate increase and an interim emergency rate increase in connection with its Oklahoma jurisdictional business relating to the generation, transmission, distribution and sale of electric energy on June 6, 1980, in Cause No. 26959, based upon a historical test year ending December 31, 1979. Thereafter, Commission Staff filed a motion with the Commission to require Applicant to update its test year and on June 23, 1980, the Commission entered its Order No. 171516 directing Public Service Company to file a new proceeding for permanent rate relief based upon a test year period ending June 30, 1980, authorizing P.S.O. to use the cost of service study which it had prepared for use in its original filing and further providing that the scope of Cause No. 26959 would be limited to the consideration of P.S.O.'s request for interim relief and that any interim relief granted would be subject to review and adjustment as necessary at the time this Commission entered its Order in connection with Applicant's request for permanent relief. In compliance with Commission Order No. 171516, P.S.O. filed on September 16, 1980, its Application commencing the above entitled Cause based upon a historical test year ending June 30, 1980, and thereafter, on January 19, 1981, pursuant to Commission Order, P.S.O. filed its Amended and Supplemental Application updating the test year for this proceeding to the year ending October 31, 1980, and adjusting its request for permanent rate relief to the amount of $142,205,669. On

October 31, 1980, this Commission held hearings in connection with P.S.O.'s interim rate increase request in Cause No. 26959 and thereafter, on December 12, 1980, this Commission issued its Order No. 180877 authorizing P.S.O. to recover interim rate relief under bond in the amount of 41.3 million dollars.

On December 10, 1980, the Commission Staff filed a motion in the above entitled Cause seeking to bifurcate that portion of Applicant's case relating to the Black Fox Station nuclear facility from the remaining portions of Applicant's Cause and urging the Commission to set all remaining portions of the Cause for hearing before a Commission Referee at the earliest possible date with the hearings in connection with the Black Fox station to be heard by the Commission, en banc, commencing September 14, 1981. On April 1, 1981, the Commission issued its Order No. 187342 denying Staff's Application for bifurcation; consolidating the above entitled Cause with Cause No. 26582, an Application and complaint which had been filed previously by the Attorney General for the State of Oklahoma; and setting all matters in the above entitled Cause for hearing by the Commission, en banc, beginning on September 14, 1981, and continuing thereafter until concluded. P.S.O. filed a Supplemental Application for interim relief on April 22, 1981, and on July 23, 1981, this Commission held hearings on the request for additional rate relief. Thereafter, on October 2, 1981, this Commission issued Order No. 199748 authorizing Public Service Company to recover additional interim rate relief under bond in the amount of 24.4 million dollars annually.

In response to a motion filed by the Intervenors, Citizens Action for Safe Energy, Inc. and others, which motion was later joined in by the Commission Staff, the Commission on September 1, 1981, issued its Order No. 197606 directing that the scope of the proceedings in this Cause should be expanded to allow the Commission to hear and consider all evidence relating to the Black Fox station project concerning its economic prudence and viability from the inception of the project to the present time; projections for capacity requirements which that project is intended to meet; estimated impact of the time of completion of such project on Public Service Company and its customers; and the capital recovery alternatives available to the various investment components of the project in the event of cancellation of project or conversion of the site to a coal fired generating facility.

At the pre-hearing conference held before the Commission on September 1, 1981, it was determined that the hearings in connection with Applicant's Cause should be divided into three phases for the convenience of the Applicant in presenting its case in which phase one would take up issues relating to Applicant's revenue deficiency, phase two would consider issues relating to cost of service, rate design and ratemaking standards as set forth under the Public Utility Regulatory Policy Act (hereinafter referred to as PURPA), and phase three would take up consideration of Applicant's future planning capacity requirements and the issues relating to the Black Fox nuclear project as identified in Order No. 197606.

Hearings were commenced before the Commission, en banc, on September 14, 1981, and were ultimately concluded on November 10, 1981. In addition to Applicant and Staff, the following intervening parties were present and participated in all phases of the hearing: the Coalition for Fair Utility Rates, Inc.; Citizen's Action for Safe Energy, Inc.; the Oklahoma Chapter of the Sierra Club and Jim Martin (hereinafter referred to collectively as the Residential Intervenors); the Office of the Attorney General for the State of Oklahoma; Oklahoma Industries for Fair Utility Rates; and the Tulsa Hospital Council, Inc. During the hearing, intervention was granted to the City of Tulsa, which Intervenor participated in phase two of the proceedings and to Western Farmers Electric Cooperative and Associated Electric Cooperative, Inc., which intervenors participated in the third phase of these proceedings.

At the conclusion of the hearings in connection with this Cause, the parties were given opportunity to submit proposed findings of fact and conclusions of law setting forth their respective positions in this Cause, and after having received proposed findings, memoranda of law, and other filings from the various participants to these proceedings, the matters herein presented were taken under advisement and come on now for deliberation and for Order of the Commission.

I. JURISDICTION

Public Service Company of Oklahoma is a corporation organized and existing under and by virtue of the laws of the State of Oklahoma and is a wholly owned subsidiary of Central and South West Corporation. Applicant is a public utility with its principal offices located in Tulsa, Oklahoma, and which has plant, property and other assets dedicated to and for the generation, transmission, distribution and sale of electric power and energy to the public in 51 counties in the State of Oklahoma. Jurisdiction of the Commission in this proceeding is based upon its general regulatory power pursuant to Article 9, §18, and related sections of the Oklahoma Constitution and the statutory provisions contained in 17 O.S. 1981, §§151 and following. The Commission finds that notice of these proceedings has been given and made as required by law and by orders of this Commission in all counties in which Applicant serves and to the Chief Executive Officer of all cities, towns and municipalities served by Applicant within its service territory.

II. RATE BASE

Applicant presented testimony and exhibits showing an Oklahoma jurisdictional pro forma rate base excluding all nuclear related Construction Work in Progress and nuclear related investments of $759,951,416. The Staff presented testimony and exhibits showing an Oklahoma jurisdictional rate base of $708,124,528. The variance in these two amounts primarily results from different treatment of non-nuclear Construction Work in Progress, plant held for future use, certain working capital allowances, deferred income taxes, advances for construction, pre-1971 investment tax credits, and customer deposits. To the extent that differences continued to ex. t between Applicant and the Commission Staff as expressed during the hearings, these items will be addressed separately.

A. UTILITY PLANT IN SERVICE

Public Service Company and the Commission Staff both included Applicant's newest coal fired generating plants, which are commonly referred to as Northeastern Station Units 3 and 4, each of which has a rated capacity of 450 megaWatts and commenced commercial operation during the test year. Northeastern Unit No. 3 became commercial on December 22, 1979 and Northeastern Unit No. 4 became commercial on September 14, 1980.

During the past year this Commission has had several opportunities to review the investment of the Applicant in these two c l fired plants and to determine whether that investment should be included for ratemaking purposes. In our Order No. 180877, entered in Cause No. 26959, we specifically found Northeastern Unit No. 3 to be used and useful to Public Service Company of Oklahoma's customers in Oklahoma and in Order No. 193600, entered in Cause No. 27203 after hearing and thorough consideration of the allegations put forth in that Cause, we again specifically found Northeastern Unit No. 3 to be used and useful to Oklahoma ratepayers and further found that it experienced a capacity factor in excess of that which would normally be expected of a 450 megaWatt coal plant in its first year of operation. We incorporate herein as fully as though rewritten at length here our findings and conclusions as expressed with respect to Northeastern Station Unit No. 3 in Order No. 180877 and in Order No. 193600.

Northeastern Station Unit No. 4 was the subject of the second interim proceeding in this Cause and in our Order No. 199748, we concluded that the evidence presented to us in this Cause established the need for Northeastern Station Unit No. 4, that its usefulness to P.S.O.'s ratepayers had been demonstrated, that a delay by the Applicant of the in-service date for this plant would have increased the cost of the plant to the detriment of Oklahoma ratepayers and that a delay in the in-service date could have resulted in a deterioration in the quality of service provided to Oklahoma ratepayers. We incorporate herein our findings and conclusions with respect to Northeastern Station Unit No. 4 as reflected in Order No. 199748.

The evidence presented to us in Applicant's permanent rate proceeding further confirms our findings with respect to these plants as stated in the above referenced Orders. Testimony in this Cause establishes that the Southwest Power Pool of which Applicant is a member recently adopted a capacity reserve margin of 18% as its minimum guideline for Power Pool members and Mr. Neal Talbot, a witness sponsored by the Residential Consumer Intervenors, testified that in light of the adoption of this guideline by the Southwest Power Pool an 18% reserve margin would be the minimum amount of reserves that a member of this Power Pool should set as a target for planning purposes. In addition, Mr. Talbot agreed that it is not unreasonable or unusual to experience some deviation below this level before a new generating plant goes into service or some deviation above this level in years immediately after such a plant goes into operation. By allowing the test year level of revenues from off system electric sales in the amount of $8,882,263 to be credited back to Oklahoma jurisdiction ratepayers, we offset 124 mW of this new plant so that Oklahoma customers are called upon to support a normalized reserve capacity of 22% only even though they retain the benefit of higher reserve levels resulting from this newly added capacity.

We therefore reaffirm our decisions rendered in Order No. 180877, Order No. 193600 and Order No. 199748, with respect to Northeastern Station Units 3 and 4 and conclude that the net utility plant in service for Applicant for the test year should be found to be $784,818,694.

B. CONSTRUCT. ON WORK IN PROGRESS (Non-nuclear)

Applicant's computation of rate base included non-nuclear Construction Work in Progress (CWIP) in the amount of $22,332,270. Staff computed CWIP for rate base in the amount of $10,261,950. A part of this difference ($4,629,844) represents the jurisdictional cost incurred by Applicant in connection with lignite leases and coal leases associated with prospective generating facilities in Texas in which Public Service Company is a co-owner along with other subsidiaries of its parent corporation. The Commission Staff recommended that these costs not be included in CWIP because they represent future fuel costs and because of the uncertainty whether these investments would be useful to Oklahoma ratepayers without an interconnection between Public Service Company and its sister utilities in Texas. During the course of our hearings in this Cause, on October 28, 1981, the Federal Energy Regulatory Commission issued an Order allowing the interconnection to proceed. We find that with the removal of this uncertainty, Applicant and its sister companies will be able to participate jointly in facilities with sister utilities and the Central and South West system and that joint participation can be reasonably be expected to benefit Public Service Company's Oklahoma ratepayers in the future. At the same time, however, these investments do represent costs associated with future generation and therefore, should not be included in rate base. Accordingly, we find that the costs incurred in connection with the lignite and coal leases should not be included in calculating Public Service Company's non-nuclear related Construction Work in Progress.

We find that $10,261,950 should be included in Applicant's rate base as a level of Construction Work in Progress upon which amount Applicant should cease to accrue allowance for funds used during construction. Public Service Company should continue to accrue allowance for funds used during construction on that level of Construction Work in Progress not included in its rate base except as hereinafter may otherwise be provided.

C. PLANT HELD FOR FUTURE USE

Applicant included investments in plant held for future use in the amount of $2,660,314 in calculating its rate base. Staff rejected these investments as a part of rate base in making its calculations for the reason that such investments were not presently used and useful. Applicant urges this Commission to consider the language of the Oklahoma Supreme Court in Southwestern Public Service Company vs. State of Oklahoma, 52 OBAJ 2657 (Supreme Court No. 54667, November 10, 1981) ____________ P.2d ____________, wherein the court stated that the factors to be weighed when making a determination of whether property by a utility for anticipated future use should be included in the rate base is whether the purchase of the property in question was made in pursuance of honest and reasonable business judgment in carrying out some definite plans or whether the expanditure was dishonest, wasteful or imprudent. Clearly, there is nothing in the evidence in this Cause to demonstrate that the investment in this property held for future use was a dishonest, wasteful or imprudent expenditure. By the same token, however, the record in this case does not demonstrate to our satisfaction that this property will be used for a utility as opposed to a non-utility purpose. Until a utility's plans are sufficiently formalized to ascertain that plant held for future use will in fact be used for utility purpose, we do not believe that investments carried under this account should be charged to Oklahoma ratepayers.

D. CASH WORKING CAPITAL

Applicant sought a cash working capital allowance in the amount of $19,467,638 while Staff recommended that the cash working capital allowance should be limited to $7,832,828. The principal difference between Staff and the Applicant related to Applicant's concern for fuel related working capital requirements. Applicant presented a lead lag study which reflected an average lag of 22 days between the date Applicant pays for its fuel and dates such expenditures are covered through customer receipts, and P.S.O. translated this lag into a cash working capital requirement of $13,174,007 for fuel expenses. Staff on the other hand contended that there is no lag with regard to fuel expenses because Applicant's fuel adjustment clause is designed to provide Applicant with current recovery of fuel expense. In any event to the extent that a lag may exist, it can be substantially overcome by rebasing of the fuel expense in Applicant's base rates to a level which more accurately reflects the current fuel costs. Fuel expense currently included in Applicant's base rates is $1 per million btu whereas, Applicant's current cost of fuel is approximately $1.96 per million btu. For administrative convenience, we find that the fuel expense for Applicant should be rebased to $2 per million btu and find that to the extent that Applicant's fuel expense is less than $2, it shall provide a credit to its customers through the fuel adjustment clause line item on the customer's bill. We conclude that as a result of this rebasing, there is no need to include a cash working capital allowance for fuel expense in rate base.

Staff's recommendation as to an allowance for cash working capital, resulted from a calculation of that portion of Applicant's annual operation and maintenance expenses excluding fuel expenses required for a 45 day period. Applicant agreed with this approach, we accept Staff's recommended method of calculation for working capital on such non-fuel related expenses, and we find that Applicant's cash working capital allowance should be $7,845,958 for the test year.

E. MATERIALS AND SUPPLIES

1. Coal stock pile

Public Service Company has requested that it be allowed to include in rate base the total amount of $24,531,532 for fuel inventory of which $19,949,274 is attributable to a coal stock pile for Northeastern Station Units 3 and 4. This coal stock pile level represents a cost of supply of coal sufficient to operate these coal fired plants for 120 days at a 75% capacity factor. Staff recommended that the coal stock pile for Applicant should be valued at the cost of a 90 day supply of coal based on the capacity factor experienced during the peak period of the test year which amount calculates to $15,381,229. Applicant presented testimony based upon industry studies and showing nation wide averages; however, we find that these generic national figures are neither relevant nor persuasive for Oklahoma utilities which burn low sulphur coal from Wyoming. Accordingly, we find that for ratemaking purposes, Applicant's coal stock pile should be valued at $15,381,229 for the test year.

2. Fuel oil

The remainder of Applicant's request for fuel inventory is $4,582,258 for fuel oil. The Staff has recommended the inclusion of $3,269,151 for this item with the difference resulting from Staff's use of the actual amount of fuel oil inventory at the test year end rather than the 13 month average of such inventory as used by Public Service Company. Staff used the year end adjustment since it reflected the lower inventory existing at test year end and resulting from a one time sale which was not expected to be replenished by future purchases. With the deduction of the proceeds of the oil sale in the amount of $666,240 from Applicant's operating revenues as an unusual and nonrecurring item, Applicant acquiesced in the Staff's treatment of fuel oil inventory, and we therefore find that the same should be valued at $3,269,151.

F. PRE-PAYMENTS

Public Service Company requested inclusion of $4,967,699 in its rate base for pre-payments. Of this amount, $3,915,509 represented deficiency payments which Applicant had made pursuant to take or pay contract provisions of its gas purchased contracts. Mr. Howard Motley, Director of Public Utilities Division, for the Commission Staff recommended that Applicant be allowed to recover a return on these deficiency payments on a current basis through its fuel adjustment clause. Applicant has requested this same treatment as to deficiency payment balances occurring in months subsequent to June, 1981, as reflected in its Application filed in Cause No. 27457. We find that Mr. Motley's recommendation is appropriate and find that our Order No. 199140, which we issued in Cause No. 27457 on September 23, 1981, should be amended accordingly. As a result, a deficiency payment balance outstanding at the end of the test year is properly excluded from rate base in accordance with Staff's recommendation.

Staff in its exhibits recommended that certain payments made by Public Service Company for the installation of their telephone system and the installation of a water line at its Riverside station should properly be reflected as expenses on annualized basis rather than as pre-payments included in the rate base. Staff amended its recommendation during the hearing to indicate that the unamortized portion be recognized in rate base. We agree with the Staff that the installation expenses associated with these items should be capitalized as recognized by Commission Staff. After deducting the above items from Applicant's requested pre-payment balance in rate base, there remains $1,150,374, which amount we find to be the appropriate amount of pre-payments for inclusion in Applicant's rate base for the test year.

G. DEFERRED INCOME TAXES

The Commission Staff recommended that 100% of the Oklahoma jurisdictional portion of Applicant's deferred income taxes be deducted from rate base and presented exhibits and testimony showing that that amount should be $95,895,198. Applicant agreed to the deduction of deferred taxes but for the inclusion of $2,202,576 in income taxes on customer deposits which Applicant believed should not be considered as deferred taxes since they were actually paid during test year. Mr. Motley testified that these income taxes had actually been paid by Applicant during the test year pursuant to a demand by the Internal Revenue Service, that such payment had been made under protest and that Applicant was seeking a refund of the taxes in litigation with the Internal Revenue Service. Mr. Motley stated that Staff's reason for not recognizing the payment of these taxes was based upon the prediction that the Applicant ultimately would prevail in the litigation and recover these taxes from the I.R.S. Mr. Motley further indicated that a failure to recognize this test year occurrence was based on an anticipated change in circumstances in the future which does not adhere to the historical test year approach. Accordingly, we find that the proper deduction from rate base for deferred income taxes should be $93,692,622.

H. SYSTEMS DEVELOPMENT INVESTMENT

As reflected below (part III.B.2.) Applicant expended the jurisdictional amount of $320,349 to modify its computer software systems for accounts payable and customer information. Staff considered these expenditures to be nonrecurring and proposed this investment should be amortized over the life of the system. To do so we must, as Staff agreed during the hearing, recognize the unamortized balance as a rate base item. Accordingly, we find that $205,868 should be included in rate base as systems development investment.

I. OTHER ADJUSTMENTS

The Commission Staff made additional deductions to Applicant's rate base for such items as advances for construction, pre-1971 investment tax credits and customer deposits. Applicant presented no testimony or exhibits specifically objecting to these adjustments recommended by Staff and the Staff recommendations with respect to these items is consistent with the position taken by this Commission for both the Applicant and other utilities operating in this State. Accordingly, we conclude that Staff's recommended adjustments to rate base with respect to these items are appropriate and we find that the same should be made.

J. RATE BASE CALCULATIONS

Based upon our findings hereinabove set forth, we find that Applicant's Oklahoma jurisdictional rate base should be reflected as follows:

Gross Plant in Service	$1,025,837,779
Accumulated Depreciation	$ (241,019,085)
Net Utility Plant in Service	$ 784,818,694
Additions	
Construction Work in Progress	$ 10,261,950
Cash Working Capital	$ 7,845,958
Materials and Supplies - Fuel	$ 18,650,380
Materials and Supplies - Other	$ 3,815,201
Pre-Payments	$ 1,150,374
Deductions	
Deferred Income Taxes	$ 93,692,622
Advances for Construction	$ 1,192,019
Pre-1971 Investment Tax Credits	$ 2,588,808
Customer Deposits	$ 9,672,179
½ Ad valorem Taxes	$ 8,631,101
TOTAL OKLAHOMA RATE BASE	$ 710,765,828

III. OPERATING INCOME

A. REVENUES

Public Service Company submitted pro forma adjustments to its operating revenues for the test year dealing with areas such as the reclassification of certain sales, annualization of sales to year end customer levels and weather normalization. The Commission Staff made adjustments in some of these areas and some additional adjustments which were not made by Applicant. After making these adjustments, Staff concluded that Applicant's operating revenues during the test year should be found to be $353,491,718, but thereafter Staff agreed that the proceeds of the sale of certain fuel oil as discussed above in the amount of $666,240 should be deducted from revenues as an unusual and nonrecurring receipt. Applicant did not present any testimony opposing the Commission Staff's adjustments except with respect to municipal discounts. The Residential Intervenors and the Attorney General asserted that additional revenues should be imputed to P.S.O. as a result of discounts which it provides to certain employees and the Intervenor, Oklahoma Industries for Fair Utility Rates, asserted that recognition should be given to Applicant's unbilled revenues so as to increase operating revenues. Each of these points of contention are discussed separately below.

1. Discounts to Municipalities

For many years Public Service Company has granted municipalities in its service territory a 40% discount for mercury vapor municipal street lighting charges and an additional 9% discount for pre-payment of their billings. During the test year the total amount of the 40% discount was $1,026,879 and the total amount of the 9% discount was $138,629. In our Order No. 168923 issued in Cause No. 26669, we concluded that in fairness to all customers, the discounts to municipalities must be reflected as earned revenue for ratemaking purposes. At that time, we neither approved nor disapproved the Company's policy concerning municipal street lighting discounts. Since issuing that Order on May 7, 1980, however, we have had occasion to examine the discounts to municipalities on a more intensified basis. We find, as reflected in the Company's tariffs, that the 40% discount which Applicant has been giving to municipalities for many years applies only to mercury vapor street lighting and thus results in a disincentive for municipalities to use the more energy efficient sodium vapor street lighting. A continuation of the municipal street lighting discount for mercury vapor street lighting is directly contrary to our efforts directed toward conservation in Oklahoma. Applicant has told us in the record before us, that if we determine not to recognize the appropriateness of these discounts, it will proceed to amend its contracts with municipalities to remove the discounts.

Staff witness, Larry Schroeder, presented testimony to us outlining a methodology for the discontinuance of these discounts while minimizing the impact on municipalities which will be losing the discount which Applicant has previously granted. Mr. Schroeder testified that the discounts to municipalities should be phased out over a four-year period and that in order to accomplish this phase out, Applicant should eliminate 10 percentage points of 40% discount each year over a four-year time frame.

2. Discounts to Employees

For a number of years Public Service Company has granted all of its employees, with over one year of service, a 50% discount on charges for electric service from the Company. In Order No. 168923, which we entered in Cause No. 26669, we refused to recognize Applicant's employee discounts for ratemaking purposes, primarily because such discounts might have the effect of providing Applicant's employees with less incentive than other ratepayers to conserve energy. During the hearings in connection with the present Cause, Applicant presented evidence to establish that during the period from 1975 to 1980, P.S.O. employees have decreased their average usage of electricity while the average residential consumer on Applicant's system has increased usage by approximately 16%. Additionally, evidence was presented to us which established that in the event this discount to employees were to be taken from Public Service Company's employees, some recognition would have to be made to those employees in terms of wages and salaries particularly with respect to those employees who are protected under collective bargaining agreements and would in all probability result in increased costs to Applicant's ratepayers. While it does not appear that the discount is a disincentive to conservation by P.S.O.'s employees, we nevertheless believe that this is an employee benefit which has outlived its usefulness. Accordingly, while we make no adjustment now, we find that Applicant should be given two years to phase out this discount and adjust wages, salaries, and benefits to eliminate the discounts in labor agreements and employee compensation packages.

3. Unbilled Revenues

Mr. Steven A. Duree, a witness for Intervenor, Oklahoma Industries for Fair Utility Rates, proposed that Applicant's jurisdictional operating revenues should be increased by $2,702,589 to recognize services which had been rendered to its customers but which had not yet been billed to the customers. During cross examination of Mr. Duree, he advised that his calculation had not made allowance for fuel expenses which would be associated with these unbilled revenues but which would be uncollected as a result of P.S.O. closing its billings for fuel expenses on the 25th of each month. Applicant presented Mr. Dwane R. Glancy as a rebuttal witness to Mr. Duree's proposal. Mr. Glancy testified among other things that test year revenues had already been adjusted by both Applicant and the Commission Staff to reflect year end fuel prices and customer usage and that these factors are the major causes of any mis-match resulting from a failure to recognize unbilled revenue as testified by Mr. Duree. As a result, the mis-match which Mr. Duree has called to our attention has been taken into consideration through the use of year ending adjustments. Accordingly, we find that it would be inappropriate to include unbilled revenues as a part of Applicant's operating revenues for the test year.

4. Test Year Revenue Summary

In view of our findings as set forth above, we find that the pro forma test year revenue for Applicant should be determined to be $352,825,478.

B. EXPENSES

Applicant's exhibits and testimony reflected non-nuclear operating expenses for the test year in the amount of $316,720,215. The Commission Staff, through its exhibits and testimony, recommended sixteen adjustments to Applicant's operating expenses for the test year and recommended that the Commission allow operating expenses in the amount of $302,710,325. Many of Staff's adjustments were not challenged on the record and accordingly we find that those adjustments which were not opposed are proper adjustments based upon testimony presented by Staff in connection therewith. To the extent that Staff's adjustments were challenged on this record, we discuss them separately below.

1. Advertising and Conservation Expenses

Applicant proposed an adjustment to test year end expenditures for advertising and conservation expense in the jurisdictional amount of $570,216 and presented testimony advising that the anticipated jurisdictional increases would involve $180,768 for Applicant's implementation of the Residential Conservation Service (RCS) program and $389,448 in expenses for communications with Applicant's customers, concerning conservation, education and industrial development. The Commission Staff recommended that the jurisdictional allowance for conservation and advertising expenses be limited to a total increase of $428,263 above those made in the test year and Applicant presented testimony to reflect that that level would be acceptable to it.

As has been done in the past, we specifically exclude all advertising and "information" communications, including Applicant's newsletter, to the extent that they relate to nuclear energy in general or the Black Fox Station, in particular.

As is discussed subsequently in this Order, Applicant is committed based upon the testimony in this record to an aggressive conservation program. In order for this conservation program to be effective so that Applicant's ratepayers and the Company can mutually benefit from the potential savings to be realized from conservation, it is important that we recognize and make allowance for the conservation expenses which this Company will of necessity be required to incur. Accordingly, we find that Applicant should be allowed an additional $428,263 for conservation expenses including advertising, and Staff is directed to monitor Applicant's expenses associated with conservation to insure that these expenditures are incurred for the purposes for which they are intended, and that they achieve the desired results.

2. Systems Development Expenditures

During the test year, Applicant expended the jurisdictional amount of $320,349 for modification of its computer software systems for accounts payable and customer information. Staff considered these expenditures to be nonrecurring and proposed that these expenses should be amortized over the anticipated life of the system. Accordingly, Staff recommended an adjustment recognizing $114,481 of the jurisdictional systems development expenses as having been made in the test year. On cross examination, the Staff agreed that if these expenses were amortized, the unamortized portion of the expenses should be included in Applicant's rate base. Applicant objected to the adjustment for the reason that it anticipates annual recurring expenditures to be equal to or greater than those experienced in the test year for the foreseeable future that there are several systems under current development which Applicant will be acquiring in the foreseeable future and that these expenditures should be considered as normal business expenses necessary to maintain productivity in the computer age. We believe that Applicant will probably find it necessary to make expenditures for computer systems development in the foreseeable future and that these expenditures may be equivalent to or exceed the level of these expenses as incurred during the test year. We also believe, however, that these investments result in software purchases which will be useful for more than one year and that our ratemaking treatment of these investments should recognize this extended usefulness. Accordingly, we find that Staff's treatment of this expense as modified and as recognized above is appropriate, and $114,481 should be recognized as a test year operating expense.

3. Postage Expenses

On March 22, 1981, the United States Postal Service increased by three cents the cost of postage for first class mail, and Applicant, among its pro forma adjustments to operating expenses for the test year, seeks an increase in postage expenses in the amount of $96,856, maintaining that although this increase did not occur during the test year it represents a known and measureable change and will result in an increase in expenses incurred by Applicant during the period in which the rates authorized by this Order will be in effect. Staff testified that the reasons for Staff's recommendation were that this allowance should not be made because the increase did not occur within the test year and because changes to test year revenue should also be made to recognize factors such as increased numbers of customers and increased usage per customer before making this type of adjustment. Accordingly, we find Applicant's propose adjustment for postage expense should not be accepted.

4. FICA Tax Expense

Applicant sought an adjustment to expenses incurred during the test year for FICA tax expense as a result of a change of federal FICA tax law, which took affect on January 1, 1981. Staff made an adjustment disallowing $178,940 of the requested increase for the same reasons as expressed above concerning Applicant's postage adjustment. Consistent with our finding above, we find that Applicant's FICA tax adjustments should be rejected.

5. Inflationary Adjustment

Applicant proposed an adjustment for attrition which will occur prospectively.

The Commission Staff recommended an adjustment to increase operating expenses by the amount of $700,041 based upon the actual inflationary trend experienced during the test year in those operations and maintenance expense accounts which were not otherwise adjusted to reflect year end levels. This adjustment applies an inflation factor to test year end balances. Accordingly, we accept Staff's inflation adjustment and reject Applicant's attrition adjustment.

6. Depreciation

Applicant presented exhibits and testimony in support of a request that the Commission approve new depreciation rates for Public Service Company of Oklahoma. The original request was filed in this Cause on October 31, 1980, based upon depreciation studies performed for Applicant by its consultant, Mr. John S. Ferguson, as of December 31, 1977, and December 31, 1978. The original filing sought approval of depreciation expense in the amount of $34,738,853. Subsequent to that filing, the Power Plant and Industrial Fuel Use Act of 1978 was amended and Applicant requested that Mr. Ferguson update his depreciation studies to recognize the effect of that amendment. In performing his services for the Applicant, Mr. Ferguson updated his depreciation study for Applicant's production plant accounts and reviewed and revised the methods for calculating rates for transmission, distribution and general plant accounts by applying the equal life group method of calculating depreciation rates for those latter accounts. As a result of Mr. Ferguson's new study, the depreciation rates for production plant was generally decreased while the depreciation rates for transmission, distribution and general plant were generally increased as a result of the application of the equal life group method. The total effect of the proposed rates resulting from Mr. Ferguson's most recent study is to decrease the jurisdictional depreciation expense for Public Service Company by $163,300.

The Commission Staff retained consultant, Ben Johnson, who analyzed the studies performed by Mr. Ferguson. Mr. Johnson recommended that the depreciation rates be lowered for steam production plant and objected to Mr. Ferguson's use of the equal life group methodology in the calculation of depreciation rates for the transmission, distribution and general accounts.

We believe that Mr. Johnson's recommendation to lower rates for steam production plant has been satisfied by the production plant study carried out by Applicant's consultant as of December 31, 1980. Accordingly, we find that the depreciation rates for steam production plant should be established as proposed by Mr. Ferguson in his updated study.

As originally filed, Mr. Ferguson's depreciation rates for transmission, distribution and general plant accounts were calculated on the average service life basis. When Mr. Ferguson updated his study, at the request of the Applicant, he applied the equal life group methodology in calculating depreciation rates for those accounts. The effect of changing methodologies from average service life to equal life group is to increase sub. ntially the depreciation rate for transmission, distribution and general plant accounts above those rates initially recommended by Mr. Ferguson and as developed in his original study.

We believe that the equal life group method of depreciation is an appropriate method of determining depreciation rates for production plant but that the average service life method is more appropriate for the more diverse groups of assets represented by transmission, distribution and general plant accounts. Accordingly, we find that the depreciation rates recommended by Mr. Ferguson for transmission, distribution and general plant accounts in his Exhibit JSF-3 to his testimony (Exhibit 123 in this record) should be accepted as the appropriate depreciation rates for those accounts and that the depreciation rates as proposed by Mr. Ferguson in his updated study for production plant should be adopted as the appropriate depreciation rates for production accounts. Based upon the application of these new rates, Public Service Company's approved depreciation expense for the test year is $32,066,476.

C. OPERATING INCOME CALCULATION

1. Economic Recovery Tax Act of 1981

Applicant presented testimony summarizing the purposes of the Economic Recovery Tax Act of 1981 as it relates to public utilities and the specific requirements which that act sets forth for actions to be taken by regulatory commissions in order for utilities to sustain the use of the accelerated cost recovery provisions for tax purposes. We find it is imperative that neither Public Service Company nor its ratepayers lose the benefit of such tax deductions under the new act.

Therefore, we authorize Public Service Company to use the "Accelerated Cost Recovery System" for calculating depreciation for income tax deduction purposes and further authorize the Company to use a full normalization method of accounting as defined and perscribed in the Economic Recovery Tax Act of 1981 and any rulings or regulations which might be promulgated to further explain or define the provisions of that Act.

2. Net Operating Income

Based on the findings and conclusions set forth above, we find the test year operating income for Public Service Company to be as follows:

Operating Revenues	$352,825,478
Operating Expenses:	
Fuel and Purchased Power Expense	$180,829,694
Other Operations and Maintenance Expense	$ 62,767,660
General Taxes	$ 24,374,118
Depreciation Expense	$ 32,066,476
Operating Expense Before Income Taxes	$300,037,948
Operating Income Before Income Taxes	$ 52,787,530
Less Income Taxes	$ 10,292,318
Net Operating Income	$ 42,495,212

IV. RATE OF RETURN

Applicant initially sought an overall rate of return of 12.08% on its capital structure as it existed at the end of the test year, which rate of return would allow a rate of return on common equity of 16.5%. During the first quarter of 1981, however, two of Applicant's bond issues matured and P.S.O. refunded $10,000,000 of series C 3 1/8% first mortgage bonds and $16,700,000 of series B 8 3/8% project bonds. While the maturing and refunding of these bonds occurred outside the test year, a change in a utility's capital structure such as this and over which the utility has no real control significantly impacts the ability of that utility to earn the authorized rate of return which this Commission orders on a prospective basis. In our Order No. 200514, which we issued in Cause No. 27275, we recognized that test year constraints should not apply to a determination of capital structure or to rate of return and in that case we recognized the issuance of two million shares of common stock which had occurred outside the test year but which was authorized by this Commission. As was the case for Oklahoma Gas and Electric Company in Cause No. 27275, a failure to recognize the retirement of these bonds for Public Service Company would result in an immediate de facto inability to earn the rate of return which is authorized by this Commission herein. Accordingly, we find that the capital structure for the Applicant should be updated for the test year to reflect refunding of these bond issues. Based upon this finding, we conclude that Applicant's capital structure should be stated as follows:

Capital Component	% of Total	Cost Rate Percent	Weighted Cost
Debt	50.96	9.577	4.88
Preferred Stock	7.08	7.187	.509
Equity	41.96		

Applicant presented Mr. Frances E. Jeffries of Duff and Phelps, an investment advisory firm specializing in utility securities, who testified in his opinion Public Service Company should be granted a return on equity of 17% to 18% in order to attract new equity for investments. Commission Staff retained Mr. A. Scott Rothey who recommended a rate of return for common equity in the range of 15.5% to 16.25%.

As we have said before, the credible witnesses who have testified before us, with respect to the cost of money and the proper rate of return which should be granted to utilities in Oklahoma, all have agreed that the establishment of a proper rate of return is a judgment factor and that reasonable men will differ to some extent based upon their analysis and perception of economic conditions in submitting their recommendations. In determining the appropriate rate of return for this Company, we must apply our own judgment in analyzing the expert testimony which we have before us and establish a rate of return for the utilities which we regulate which complies with the mandates of the Hope and Bluefield decisions of the United States Supreme Court. Accordingly, we find that Applicant should be allowed to earn an overall rate of return of 12.313%.

V. REVENUE DEFICIENCY

Based upon our findings in parts II, III, and IV of this Order, we conclude that Applicant has a revenue deficiency which is calculated as follows:

Total Oklahoma Jurisdictional Rate Base	$710,765,828
Rate of Return	12.313%
Net Operating Income Required	$ 87,516,596
Pro forma Net Operating Income	42,495,212
Operating Income Deficiency	$ 45,021,384
Income Tax (48.077%)	41,686,428
Franchise Tax (1.50%)	1,320,424
Total	$ 88,028,236
Less: Gross Profit from Electric Off-System Sales	8,882,263
Revenue Deficiency	$ 79,145,973

The revenue deficiency which we have found to exist exceeds the two awards of interim relief which have been granted to Public Service Company under bond and subject to refund which might have been directed in this Order. Based upon the amount of revenue increase which we find must be granted by this Order, we find that the bonds undertaken by Applicant in connection with the interim relief which has been granted should be absolved and the sureties on such bonds should be released.

V. COST OF SERVICE AND RATE DESIGN

A. PUBLIC UTILITY REGULATORY POLICY ACT (PURPA) CONSIDERATIONS

Section 111 of PURPA sets forth six standards which this Commission must consider under the federal scheme and either accept or reject for rate setting purposes for electric utilities operating within our jurisdiction. Those six standards are: (1) cost of service, (2) declining block rates, (3) time of day rates, (4) seasonal rates, (5) interruptible rates and (6) load management techniques. This Commission presently has under advisement Cause No. 26600, a generic proceeding in which these six standards are being considered for application on a state wide basis. In addition, certain of the parties to this proceeding have requested that the six standards set forth in PURPA §111 (d) should be considered by us as they apply to rates to be set for this Applicant based upon our revenue requirement finding in this proceeding. We will discuss each of the six standards separately as they apply to Public Service Company of Oklahoma and based upon the evidence presented in this case.

1. Cost of Service

We believe that the cost of service standard of PURPA and the associated rules promulgated in connection therewith, appear to imply the following intent: First, that rates should be based upon the cost of providing service to the maximum extent practicable. Second, that the costing methods approved should provide for recognition of cost differences with respect to daily and seasonal time periods. Third, that the costing methods approved should provide for separation of costs between customer demand and energy components and fourth, that the costing methods approved should take into account the extent to which total costs are likely to change if additional kilowatts and kilowatt hours of electric energy are produced and delivered to electric consumers at various times.

The fourth stated intent appears to imply a requirement to use marginal costs as the appropriate cost measurement in developing cost of service studies. We must note at the outset that cost of service studies for our electric utilities in Oklahoma have traditionally been based upon embedded or average accounting costs primarily because the total revenue requirement for our electric utilities is based upon average accounting costs. The electric utility industry has developed numerous cost of service study methodologies and the allocations which are and can be made by a cost of service expert using any given methodology are virtually infinite. Recognizing this, we believe that equally appropriate cost apportionments could probably be accomplished using either margin or average costs. At the same time, however, since average costing is used in Oklahoma to develop the total revenue requirement, it would appear to us that average costing would be the more straight forward approach in developing inter-class revenue requirements to meet the revenue requirement for the Company as a whole. In reaching this conclusion however, we do not reject marginal cost pricing since we believe this technique has particular application in certain instances. For example, we believe some recognition should be taken of marginal energy costs, particularly where discretionary or optional tariff features are proposed and marginal capacity and energy costs should be provided in the context of any plan filed for load management or interruptible rates.

This Commission has considered the cost of service in deciding how to establish rates in Oklahoma, but cost of service is not the only factor which should be considered in establishing rates for Oklahoma customers. As reflected in the testimony presented to us in this case in evaluating customer equity, recognition should also be given to value of service, to customer impact and to social considerations. Rates cannot be established based solely upon the cost of service standard, and this Commission does not believe it was the intent of Congress to limit rate setting consideration to cost of service when it included the words quoted and emphasized below:

"Section 111 (d) (1) COST OF SERVICE. - Rates charges by any electric utility for providing electric service to each class of electric customers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class. . . " (Emphasis ours)

We find that there is no universally accepted cost evaluation technique in the electric utility industry. We further find that cost of service is a valuable tool as one measure of customer equity and that for the purpose of this Applicant, the cost of service standard should be adopted to the extent that it is compatible with our discussion herein. We will continue to the maximum extent practicable to give weight to the cost of service in the rate design process, while at the same time taking into consideration to the extent that they apply, other customer equity factors which should be considered in designing rates which will provide this Applicant an opportunity to earn the revenue authorized by our Orders.

Mr. Larry Schroeder in his testimony presented in this case (Exhibit No. 159) has made a number of recommendations relating to aspects of cost of service studies which could, in his judgment, be changed from the methodology which is currently employed by this Applicant. We believe that his testimony has relevance to cost of service studies generically and find that his testimony should be considered again by us in our evaluation on a generic basis of the cost of service standard in Cause No. 26600.

2. Declining Block Rates

The declining block rates standard of PURPA as set forth in §111 (d) (2), simply stated, provides that the energy component of a rate charged by an electric utility may not decrease as kiloWatt hour consumption by customers on that rate increases during a billing period unless the utility can demonstrate that the cost of providing electric service to that class decreases as consumption for that class increases during a billing period. As the evidence in this case reflects, it is important to note that a kiloWatt hour rate without a separate demand charge is made up of three major cost classifications: customer costs, capacity costs and energy costs. The declining block standard relates only to energy costs. There is no inconsistency with the declining block rates standard of PURPA when rates for electric service which: 1) capture customer and capacity costs at a decreasing rate with increasing usage, and 2) capture energy costs at a constant rate at all levels of usage. The testimony before us in this case indicates that customer related unit costs tend to decline as a function of usage although the customer related costs may be larger in absolute amount for a large customer than for a small customer. Based upon this interpretation of the declining block rate standard of PURPA, we believe that this standard should be adopted in the structuring of rates for this Applicant.

3. Time of Day Rates

The time of day rate standard established by PURPA provides that the rates charged by an electric utility for providing electric service to each class of consumers, should be on a time of day basis reflecting the costs of providing electric service to the class at different times of the day unless those rates are not cost effective with respect to the class as determined by cost of service study. The testimony in this case establishes that in evaluating the time of day rate standard, we should consider customer equity, administrative feasability conservation and efficiency in the use of resources. Customer equity, of course, requires consideration of cost of service in customer impact and the testimony in this case indicates that time of day rates have a potential of providing a more accurate distribution of costs than do rates which do not incorporate daily time differentiated features. On the other hand, however, time of day rates on individual bills could have a substantial impact. With respect to the administration of time of day rates, we must consider the cost availability, and reliability of meters, the flexibility of the utility's customer accounting system, and the problem of estimating billing units on a time of day basis. Based upon the testimony before us, the cost per meter for residential consumers in order to establish time of day rates for that class would be three to six time the cost for a meter now being used to serve the residential class. Recording demand meters, which are used to register the usage of large utility customers, can be acquired at a cost of $350 to $450 and the evidence in this case establishes that Applicant has a present policy of installing this type of meter on all customers whose demand exceeds 1500 kiloWatts of capacity. There is nothing in this record to indicate the exact extent of modifications to Applicant's billing system which would be required if the time of day rate standard were adopted for this utility and as reflected above, the only customers for whom load data currently is available on a time of day basis for all customers in the class is the large power and light class. Applicant has a load research sample consisting of a small group of customers who have recording demand meters but at the time of hearings in this case, data accumulated from this research sample was insufficient to allow the development of time of day rates. Accordingly, we find that the time of day rates standard should not be adopted for Public Service Company at this time but Applicant is directed to continue its research in this area including the search for low cost demand meters for those classes which are not currently served through recording demand meters and that Applicant develop and submit to us, as quickly as possible but not later than its next general rate proceeding, a proposed time of day rate which would be available on an optional basis to those customers with demand in excess of 1500 kiloWatts and which are currently served by recording demand meters.

4. Seasonal Rates

The seasonal rate standard of PURPA seeks to establish rates based on the cost of providing service to a particular class at different times of the year to the extent that such costs vary from season to season for the utility. With respect to Public Service Company, it is clear that there are significant variations in seasonal usage patterns on the Company's system. Applicant's rates have had a seasonal differential, which is intended to recognize this seasonal usage variation, and based upon the testimony presented to us, we conclude that the months of June through September are the only months where there exists a reasonable probability of the system peak occurring and these are the months in which the demands from the system are at a reasonably high percentage of the system peak load. In addition, the evidence in this case also supports the finding that the residential and commercial classes of customers tend to exhibit more seasonal variation in loads than do industrial consumers, as a group. Mr. Schroeder has testified that the use of demand ratchets can be a substitute for seasonal rates; he expressed the opinion that a seasonally differentiated demand ratchet can be as effective as seasonal energy or demand rates in terms of accurate cost recovery. Mr. Schroeder concluded that seasonal rates would not further the conservation objective directly although efficiency might be enhanced through the effect of seasonal rates on a utility's system load factor.

We believe that Applicant's proposed tariffs for the residential and commercial classes appropriately recognize in the absence of a seasonally based cost of service study, the differential which should exist between the summer and winter periods. In addition, a seasonal rate including a seasonal demand ratchet for large power and light customers should be developed and proposed for this class of customers in Applicant's next rate filing.

5. Interruptible Rates

The interruptible rate standard of PURPA provides that every electric utility must offer each industrial and commercial electric consumer an interruptible rate which reflects the cost of providing interruptible service to that class of which the customer is a member. Interruptible rates would apply to loads which are interruptible through communication with a customer on a pre-arranged basis or through radio signal controlling a specific portion of a customer's load. We believe that interruptible service should be offered to industrial and commercial customers of Public Service Company on a voluntary basis and that Applicant should file, within six months, an optional interruptible tariff providing that interruptible service can be obtained from the Company on a pre-arranged basis under contract which contract will specify the contract duration period, the specific circumstances surrounding interruptions of service and level of credit which will be applied to those customers who agree to take an interruptible service.

In preparing for this filing, Applicant should conduct a survey of its Large Power and Light Class to identify the interruptible potential available from these customers and include the results of this survey in the filing to be made. Applicant should advise the Director of Public Utilities Division, with respect to customers which express interest in this type of service. In addition, we believe that Applicant should continue its efforts with respect to radio controlled load interruption and provide to this Commission not later than the filing of its next rate proceeding, a cost of service study reflecting the cost effectiveness of interrupting air conditioning load by radio controlled devices.

6. Load Management

The PURPA load management technique standard provides that the utility shall offer electric consumers such load management techniques as this Commission determines will be practicable, cost effective, and reliable, and which will provide useful energy or capacity management advantages to the electric utility. Clearly, the PURPA load management standard leaves the door open to this Commission and to the utilities in Oklahoma to be innovative and creative in our total conservation efforts. The testimony in this case supports our finding that Applicant is investigating at load management alternatives which are considered most likely to be cost effective; that testimony also brings into question the cost effectiveness of certain portions of load management programs mandated by the federal government. Before any load management program can be approved by this Commission, we believe that a cost benefit evaluation with respect to that program must be conducted and submitted to us for our review. We expect Applicant to exert a consciencious effort to reduce its capacity requirements through cost effective load management efforts. Accordingly, we find that Applicant should file with this Commission, within six months from the date of this Order, a comprehensive load management plan detailing all technically feasible alternatives and the Company's proposed implementation plan for each alternative reflecting an incremental cost/benefit analysis. Thereafter, we find that Applicant should file with each subsequent rate Application an evaluation of each load management program which evaluation would should include at a minimum the evaluation of the success of the program, customer participation, cost benefit analysis and net changes in energy usage and load patterns attributable to such programs.

B. COST OF SERVICE

As a part of its filing and in compliance with this Commission's minimum standard filing requirements, as amended herein by Commission Order, Applicant filed an embedded cost of service study reflecting jurisdictional and inter-class allocations and the evidence in this case establishes that the methodology used by Applicant in this Cause is the same as that which was used and approved by this Commission in Applicant's last request for permanent rate relief (Cause No. 26669). Certain consumer intervenors presented testimony and exhibits relating to cost of service through two witnesses, Dr. Eugene Coyle and Mr. George Sterzinger, both of whom performed cost of service studies using methodologies which differed from that used by Public Service Company and in which each of them reached different conclusions relating to the costs of providing service to the various rate classes. In conjunction with their cost of service studies, Dr. Coyle and Mr. Sterzinger presented testimony recommending that the Commission reject Applicant's proposed rate structure and order implementation of rates which were generally more favorable to Applicant's residential and commercial customers. Oklahoma Industries for Fair Utility Rates presented the testimony and exhibits of Mr. Steven A. Duree, who espoused the position that Applicant's industrial customers in the large power and light class were paying rates disproportionately high in relation to the cost of providing service to the members of that class. Mr. Duree generally supported the rate structure proposed by Applicant as representing a step toward overcoming what he perceives are disproportionate rates presently being paid by P.S.O.'s industrial customers.

Substantial testimony was presented by the Applicant and by Intervenors with respect to the relative merits of their own cost of service studies and the problems and inconsistencies which the respective parties perceived to exist in cost of service studies which resulted in conclusions differing from their own.

The Residential Intervenors urge in their proposed findings that we utilize the mean average of the allocation factors as developed by the Company and by their witnesses, Dr. Coyle and Mr. Sterzinger. In rejecting this proposal, we must recognize ab initio the substantial disparity existing in the Coyle and Sterzinger line loss calculations and their resultant expansion factors when compared to line loss calculations examined by this Commission in the past. For example, in Order No. 147881 issued by this Commission on December 12, 1978, this Commission adopted our current Rule 55(b) in which 2.5% was recognized as losses associated with off-system sales of electricity-sales which occur at service level one (69,000 volts or higher). This is comparable to the level one line loss utilized by Applicant and as testified by Mr. J. W. Raper of Public Service Company of Oklahoma. The Residential Intervenor witnesses on the other hand assigned line losses at level one of 5.6843% (more than twice what we have previously recognized for this level of service) and additional line losses at level two (33,000 to 41,000 volts) of only .0281%. Line losses at level one are derived from transformation at the generation plant and transmission lines while line losses at level two are derived from transformation at the substation and transmission lines. Mssrs. Coyle and Sterzinger would have us believe that line loss experienced by an electric utility at level one is over two hundred times greater than that experienced at level two. We cannot accept their proposition. Demand and energy allocations are based upon line losses assigned to all classes of service. Erroneous line loss calculations will distort the results of any cost of service methodology rendering the results unreliable. Accordingly, we reject the "Monte Carlo" method of developing allocation factors in this case as proposed by the Residential Intervenors.

After hearing all of the evidence relating to the cost of service studies presented and after giving full and fair consideration to all of the evidence presented in this record to us during the hearing, we find that Applicant's cost of service study was properly performed, that the results of the study were properly used by Applicant and that the interclass allocations presented in Applicant's cost of service study should be relied upon by us to the extent that we find cost of service should be used in establishing an appropriate rate structure under which the Applicant should be allowed an opportunity to earn its allowed rate of return. At the same time we conclude that the jurisdictional allocations made by Applicant's cost of service study are appropriate and those jurisdictional allocations factors have been used to the extent that they apply in parts II and III of this Order as set forth above.

C. RATE DESIGN

1. Limited Usage Residential Service Rate

During these proceedings, Applicant's witness, Mr. James B. Long, was asked by the Commission to investigate the feasability of a lower rate for Public Service Company's low use customers. Applicant conducted such an investigation, developed a Limited Usage Residential Service (LURS) rate proposal and submitted the same in Cause No. 26965, the Commission's generic PURPA "Lifeline" proceeding, which was being heard by a Commission Referee at the same time the hearings in this Cause were in progress. A copy of the proposed LURS rate was admitted as an exhibit in this Cause, and we take judicial notice of the testimony presented by Applicant in Cause No. 26965 relating to the proposed LURS rate tariff.

In summary, the LURS rate would be available to Applicant's customers whose monthly usage is consistently below 400 kilowatt hours and would consist of a $4.50 per month customer charge with a flat energy rate of 4.136¢ including fuel rebasing as herein ordered for each kilowatt hour used by the customer. Approximately 30,000 customers on Applicant's system would qualify for this rate, the rate appears to be cost justified and the impact on other residential customers would not be substantial in as much as it equates to the rate as it would have existed for this level of usage prior to the installation of Northeastern Station Units 3 and 4 and the interim increases granted to Applicant to recognize the investment in those plants.

We believe that the LURS rate should be placed into effect so that a true assessment of its impact on low usage customers can be made. In addition, we direct that Applicant in its next rate proceeding develop to the extent that it can do so an intra-class cost of service study which investigates the cost of providing service to the consistantly low usage customers and which reflects the impact of this rate on other customers within the residential consumer class. Accordingly, we approve the implementation of Applicant's LURS rate and direct that it be incorporated within the rate structure which we approve herein.

2. Customer Charges

As a part of its proposed rate structure, Applicant has advanced an $8 customer charge for all residential customers based upon the results of Applicant's cost of service study as presented herein. This proposal was modified subsequently with Applicant's proposed LURS rate discussed above. Mr. Schroeder testifying for the Commission Staff recommended that a customer charge should be included but felt that the customer charge should be approximately $4.50 rather than the $8 proposed by Applicant with the difference being attributable to the distribution system beyond the service drop which was included in the customer charge under Applicant's cost of service study. Mr. Sterzinger, on behalf of certain consumer intervenors, testified that he favored the use of a minimum bill in the range of $3 to $3.50 rather than a customer charge.

In view of the very low minimum bill which is now in effect on Applicant's tariffs, we feel it is more appropriate to limit the customer charge to $4.50 as proposed by Mr. Schroeder. At the same time we believe that a minimum bill should be approved which is composed of the customer charge and a minimum usage level for those customers who do not qualify for the LURS rate. Accordingly, we find that the general residential tariff should provide for a minimum bill of $8 which amount includes the $4.50 customer charge which we find to be appropriate.

3. Fuel Costs

As reflected above (Part I. (d) of this Order), we find that Applicant should restructure its base rates so as to recover $2 per million Btu in fuel costs (including 7.8621% for line and unaccounted losses) through those rates and further find that to the extent Applicant's fuel expense is less than $2 per million Btu, Applicant shall provide a credit to its customers through the Fuel Adjustment Clause line item on the customer's bill.

4. Conclusions

Except to the extent that we have made findings to the contrary in Part V of this Order, we concur in the basic methodology utilized by Applicant in designing rates to recover its revenue deficiency. In view of the adjustments which we have made to Applicant's overall request and the specific rate design determinations made by us as hereinabove set forth, it will be necessary for Applicant to revise the rates which it has proposed to comply with these findings and with out determination with respect to Applicant's overall revenue requirements. We therefore find that Applicant should design and file rate tariffs which will comply with the provisions of this Order while recognizing customer impact as testified by Mr. Schroeder of the Staff and that the same may be implemented immediately upon approval of those tariffs by the Director of Public Utilities Division for this Commission, provided however, Applicant may not prorate the effect of this rate Order between billing cycles.

VI. CONSTRUCTION WORK IN PROGRESS - BLACK FOX NUCLEAR FACILITY

Public Service Company, as a part of its Application for rate increase, seeks to include approximately $132.3 million of investment related to the Black Fox Station nuclear project as Construction Work in Progress in its rate base. In response to a motion filed by certain consumer intervenors, in which the Commission Staff joined, we issued Order No. 197606 in this Cause expanding our scope of inquiry with respect to the Black Fox Station to include projections for capacity requirements which the Black Fox project is intended to meet, the economic prudence and viability of the project from its inception to September 1, 1981, the estimated impact of the completion of the project on Applicant and its customers, the regulatory treatment which might be afforded to Applicant in the event a determination is made to cancel the project and capital recovery alternatives which might apply to various investment components of the project in the event of its cancellation or conversion to a coal fired generating facility. In response to the testimony and evidence presented by Applicant with respect to these issues, the Commission Staff presented testimony of witnesses from Touche Ross & Company, the consultant retained by the Staff to perform an economic viability study of the project, and certain consumer intervenors presented the testimony of Neal Talbot with Energy Systems Research Group, Inc. and Mr. Amory B. Levins. Applicant's co-owners in the project, Western Farmers Electric Cooperative and Associated Electric Cooperative, Inc., intervened to participate in this portion of the proceedings and presented testimony of Mr. W. B. McClendon of Western Farmers and Mr. Wesley R. Ohrenberg of Associated Electric whose testimony was admitted by stipulation of the parties.

A. CAPACITY REQUIREMENTS

1. Load Forecasting

The validity of Applicant's plans for additional future capacity depends largely upon the validity of its load forecasting which was a major consideration in Applicant's last rate case, Cause No. 26669. In our final Order issued in connection with that Cause (Order No. 168923), we stated that it was our opinion that methods more formalized and refined than those utilized by Public Service Company for projecting usage and growth were available and urged Public Service Company to reevaluate its approach giving serious consideration to the available alternatives and methodologies in the area of forecasting. In response to our urgings, Mrs. Nancy L. Stainer, on behalf of Applicant, testified that the Company retained the consulting firm Ernst and Whinney to assist in the development of a "state-of-the-art" forecasting model for Public Service Company. Applicant presented substantial testimony to demonstrate that it now is using forecasting models and forecasting techniques which do reflect the current state of the art. Based upon all of the testimony and evidence presented, we find that the present forecasting techniques utilized by Applicant do represent the state of the art and can be relied upon both by Applicant and by this Commission for planning purposes.

Mr. Talbot, on behalf of Energy Systems Research Group, criticized Applicant's forecast primarily for the reason that it did not give adequate consideration to the impact and effect which conservation would have upon demand. On the other hand, Applicant presented testimony which indicated that the forecasting models did give consideration to conservation and Mrs. Stainer, for the Applicant, testified that using Energy Systems Research Groups forecasting model and substituting the number of residential customers forecast for Public Service Company, she obtained results reflecting slightly higher residential sales than those forecast by Applicant through the late 1990s. As a result, we conclude that Applicant's forecasting models and those of Energy Systems Research Group gives substantially the same consideration to the impact of conservation.

Mr. Sam Rhodes, of Touche Ross & Company testified that his firm had reviewed both of the forecasts submitted into this record during the study which they had performed for the Commission, and they had concluded that the Applicant's forecast could be relied upon as a planning tool to evaluate future load requirements and that Applicant's forecast could in fact be slightly understated.

Accordingly, we find that Applicant has made significant improvements and refinements in its load forecasting techniques and that the forecast which Applicant has submitted may be relied upon for planning purposes.

2. Load Management

An integral part of Applicant's load forecast is its load management program by which Applicant seeks to reduce demand by 120 megawatts in 1985, 254 megawatts by 1990, and 684 megawatts by 1995. Mr. Rhodes testified that Applicant's load management program is ambitious and aggressive and expressed the concern that Applicant's program goals may be somewhat optimistic.

Based upon the evidence presented to us, we find that Applicant has embarked on the first steps of an ambitious load management program which is designed to reduce peak load growth; but we further find that the load management program, which Applicant has presented, is in its embryonic stages, and Applicant on the record was unable to quantify the megawatt capacity savings which it expected to achieve from specific programs which would total the targeted load management program objectives as set forth on this record. We believe, however, that Applicant has demonstrated a committment to the load management program which it outlined, and we find that Applicant should continue to develop and expand this program in the manner it has outlined.

All parties who participated in this portion of Applicant's case, presented evidence emphasizing the importance of conservation as it relates to future capacity requirements and the witnesses who appeared on behalf of these parties agreed that both Applicant and its ratepayers will benefit if future demand can be reduced through conservation efforts at a lower cost than would be required to meet that demand by construction of additional generation facilities. This Commission has stated on many occasions that it is vitally interested in furthering conservation of all of our capital and energy resources. The evidence in this case establishes that Applicant has taken the first steps toward an active and productive conservation program and Applicant's increased efforts in this area will, we believe, benefit both Public Service Company and its ratepayers.

3. Capital Constrained Load Forecast

Applicant has combined the results of its load forecasting studies performed using its forecasting models, as discussed above, with its load management goals, which we have discussed above, to present its capital constrained load forecast. Based upon our review of all of the evidence presented, we conclude that even with Applicant's capital constrained load forecast, there exists a need for additional capacity in the future; that such need for capacity in excess of that to be provided to Applicant from the Okla-Union facility could exist as early as 1988, and that there will be sufficient demand to require additional generating capacity in the amounts presently planned by Public Service Company. We therefore conclude that Applicant's projections of future requirements for generating capacity are reasonable and that Applicant acted prudently in planning for additional generating capacity in the amounts presently set forth in its expansion plans. While all parties fervently hope that aggressive conservation and load management strategies will reduce the need for future generating capacity, those strategies must be devleoped and implemented before results can be demonstrated and relied upon for planning purposes. All parties agreed that forecasts should be continually monitored and updated, and we believe that the Commission's Advanced Planning Rules are an essential form for this process.

B. PRUDENCE AND ECONOMIC VIABILITY OF THE BLACK FOX STATION PROJECT

1. Project History

The evidence in this case indicates that Public Service Company has been involved in nuclear research and development since 1957. In 1968, Applicant prepared and issued a generation expansion study which evaluated the economics of natural gas, coal and nuclear fuel as boiler fuels and concluded that because of the uncertainties surrounding the future costs and availability of natural gas, Public Service Company's system should be planned to provide for a fully diversified fuel mix by the addition of coal fired and nuclear fueled generation stations. In January, 1973, Public Service Company announced its intent to construct a nuclear power plant near Inola, Oklahoma and thereafter filed an Application before this Commission (Cause No. 24393), in which Applicant informed the Commission of its intent to build a nuclear electric generating facility at the Inola sight. After the taking of evidence, the Commission issued its Order No. 100753 on October 24, 1973, finding that the site was an appropriate location for a generating facility and further finding that this Commission has no authority to approve the type and kind of generation station planned for the reason that it had been pre-empted from making such a decision by federal legislation. From that point forward until this Cause was filed, regulatory activity in connection with the Black Fox nuclear project has been restricted to proceedings before the Nuclear Regulatory Commission. In that connection, this Commission has continuously recognized and continues to recognize the pre-emptive authority of the Nuclear Regulatory Commission with respect to the construction, operation and decommissioning of nuclear power plants and all safety issues associated therewith.

Applicant presented testimony to demonstrate that during the period from 1973 through early 1979, numerous proceedings were had before the Nuclear Regulatory Commission, which hearings covered all aspects of the project including economics, engineering, environmental and safety considerations. On July 26, 1978, the United States Atomic Safety and Licensing Board issued a limited work authorization for non-safety related work, and construction began on the project immediately thereafter. In February, 1979, the N.R.C.'s safety hearings were completed and Applicant had satisfied all requirements for a construction permit. At the close of those hearings, a complete cost assessment and scheduling update was performed by the Company in anticipation of receiving a construction permit by July, 1979.

In March, 1979, an accident occurred at Three Mile Island Unit 2 nuclear facility, the impact of which was not immediately known. Applicant presented testimony indicating that subsequent to the Three Mile Island accident, Public Service Company made extensive efforts to obtain specific information concerning new licensing requirements which it would have to meet for the Black Fox station and continued to seek construction authority on its licensing application. By the fall of 1979, it became apparent that the Nuclear Regulatory Commission had declared a moratorium of uncertain duration on nuclear licensing activities. Faced with the uncertainty as to when a construction permit would be received, Applicant demobilized its field activities on the Black Fox Station and placed the project in what P.S.O. witnesses have described as a "survival mode". Because of the uncertainties, with respect to the licensing requirements and procedures procedures at the Nuclear Regulatory Commission, Applicant determined that it would be impractical to update the $2.39 billion cost estimate which it had made in April of 1979 and which was predicated on in-service dates for Unit 1 and 2 of 1985 and 1986, respectively.

On August 27, 1981, the Nuclear Regulatory Commission approved new regulations for the licensing of nuclear facilities, and as a result of this action, Applicant determined that it would now be feasible to perform a cost and schedule update for the Black Fox project. Based upon this action by the N.R.C. and in response to this Commission's

Order, Applicant and its co-owners retained Management Analysis Company of San Diego, California to perform a cost and schedule update, and the co-owners directed Black and Veatch, the architect and engineer on the project, to perform a study of the cost of a comparable coal fired generating facility.

The evidence in this case establishes that Public Service Company has operated as the project manager for this project since its inception, and that Western Farmers Electric Cooperative owns 17.391% of the Black Fox station and as of August 31, 1981, had invested $64,618,095.05 in the project, while Associated Electric Cooperative, Inc. owns 21.739% of the Black Fox station and as of September 30, 1981, had invested $84,282,516.69 in the project. On September 28, 1978, an agreement was made between Public Service Company of Oklahoma and Associated Electric Cooperative, Inc. and Western Farmers Electric Cooperative, which agreement sets forth the responsibilities and liabilities of the co-owners in the construction of the Black Fox Nuclear Electric Generating Station.

2. Economic Analysis

a. Nuclear vs. Coal Construction Costs

Extensive testimony was presented to us comparing the relative economic advantages of nuclear and coal fired generation capacity. The Applicant's initial filings in this portion of the case portrayed its perception of the present cost of nuclear construction on a generic basis through testimony of Company witnesses and certain consultants. Later during the proceedings, Applicant presented testimony of Mr. Kent R. Brown with Management Analysis Company to provide a Black Fox specific cost and scheduling update and Mr. John Robinson of Black and Veatch, to provide a more specific estimate for the construction of a comparably sized coal plant. The Commission Staff utilized Touche Ross & Company to develop generic construction cost estimates for a nuclear facility equivalent to the Black Fox project and for coal fired plants with capacity equivalent to Applicant's share in the Black Fox facility. The Coalition for Fair Utility Rates, the Sierra Club and Citizens Action for Safe Energy secured the services of Energy Systems Research Group, Inc., which utilized its internal data base and presented evidence and testimony through Mr. Neal H. Talbot relating to their generic estimates for the cost of construction of nuclear and coal facilities with capacities equivalent to that of Black Fox.

In making its comparison of coal and nuclear capital cost projections, Touche Ross utilized two 1150 megawatt nuclear units and three 770 megawatt coal units with in-service dates for the nuclear units of 1991 and 1994 and in-service dates for the three coal fired units of mid-1991, early 1993 and mid-1994. Touche Ross & Company concluded that the nuclear construction project would cost in the range of $8.18 billion to $10.12 billion and that the coal fired units would cost in the range of $5.0 billion to $5.8 billion. Mr. Thomas J. Flaherty testified that a slippage of one year would escalate the cost estimate for the nuclear facility by $1.06 billion. Mr. Sam Rhodes testified that based upon the levelized bus bar costs over a ten year period, the coal plants would have an economic advantage over the nuclear plants but that if levelized bus bar costs were calculated for the lives of the respective plants, nuclear fired capacity would have a slight advantage based upon the cost estimates which Touche Ross presented.

Mr. Neal H. Talbot of Energy Systems Research Group, Inc. testified that based upon the data base which his firm had accumulated representing a cross section of the industry and assuming in-service dates for two nuclear units of 1991 and 1994, the capital costs for the construction of such a nuclear project would be $15.1 billion whereas his firm's estimate of the construction of equivalent coal fired capacity would cost $3.11 billion thus giving a substantial advantage to coal over nuclear generating capacity.

Public Service Company's planning has relied upon in-service dates for Black Fox Units 1 and 2 of 1991 and 1993, respectively. Mr. David Kettler, of Ebasco Services, Inc., testifying on behalf of Public Service Company, advised that his company has performed several studies comparing the costs of coal and nuclear generation and testified that on a generic basis, those studies indicate a continuing viability for nuclear generation based on a political/licensing scenario that enables a utility to authorize, design, construct, and bring a nuclear unit on line within twelve years. He further testified however, that based upon his firm's most recent update to their generic studies, reflecting changes in capital costs, western coal generating facilities now have a 2.7% advantage over the nuclear option in the size range equivalent to the Black Fox project. Mr. Kettler qualified his testimony by reiterating that his study is generic and can be used for planning trends only and that a site specific detailed study should be undertaken before proceeding with any specific project.

Mr. John Robinson, of Black and Veatch, Applicant's consulting engineers, testified that barring unreasonable delays in construction and assuming licensing would proceed on a straight forward basis, his firm estimated the cost of construction of a coal plant of equivalent capacity to the Black Fox project would be $2.2 billion cash, and Mr. William R. Stratton of Public Service Company applied Applicant's AFUDC rate to escalate that cost to $2.8 billion. Mr. Kent R. Brown of Management Analysis Company presented his firm's conclusions to the date of the hearing for Black Fox site-specific capital costs and scheduling using his firm's probablistic analysis. His testimony reflects that Applicant has a 10% probability of being able to complete the Black Fox project in the 1991 to 1993 time frame and that the Company has a 50% probability to complete the project with Unit 1 in service in 1993 and Unit 2 in service in 1995 at a cost in cash of $4.81 billion. Mr. Stratton, in his testimony, applied the Company's AFUDC rate to that cash projection to estimate that the costs of the project with the 1993 and 1995 in-service dates would be $6.62

billion. Mr. Stratton presented ten year levelized bus bar costs for comparative purposes and his calculations on this basis reflect the same conclusion as was reached by Touche Ross & Company. Mr. Stratton testified however, that in his opinion, it is more appropriate to compare the nuclear and coal options on a life of project, thirty year levelized bus bar cost basis, since the ten year levelized bus bar cost basis distorts the results in favor of the coal option. On a thirty year levelized bus bar cost basis, Mr. Stratton concluded that the costs provided to him by Black and Veatch and Management Analysis Company gave nuclear and slight advantage over coal even with in-service dates of 1993 and 1995 for the nuclear option.

b. Financial Impact

Applicant ran financial studies on its corporate financial model using Management Analysis Company and Black and Veatch costs to determine the financial impact on the Company if it proceeds with the construction of the Black Fox project. Only Construction Work in Progress studies were run as testified by Mr. Stratton for the Company since time constraints did not permit the generation of AFUDC studies. Touche Ross & Company performed analysis of the effect of the construction of a nuclear facility on the financial condition of Public Service Company using both AFUDC and CWIP scenarios. Based upon Touche Ross & Company's low case capital cost projections, the Staff's consultants concluded that without the inclusion of CWIP in rate base when construction activity increases the financial condition of Public Service Company would quickly deteriorate to unexceptable levels. The consultant's analysis further shows that even with a total inclusion of CWIP in rate base for the nuclear plant, minimum standards of internal cash generation could not be achieved. Applicant's financial analysis resulted in findings under CWIP regulation which were extremely close to that of Touche Ross and Applicant concurred with Touche Ross's projections of devastating results under AFUDC regulation.

c. Customer Impact

The evidence in this case clearly demonstrates that whether a nuclear facility is built or Applicant were to convert its Black Fox nuclear facility to a coal generating station, Public Service Company's customers will experience a substantial impact in their rates. As reflected above, the cost to construct coal fired generating facilities, to replace Applicant's share of the Black Fox projected capacity, ranges from $2.8 billion (Black and Veatch estimate with AFUDC) to $5.8 billion (Touche Ross high case). The cost to construct the nuclear facility ranges from $6.26 billion (MAC estimate with AFUDC) to $15.1 billion (ESRG). Based on the range these estimates, it is clear that the nuclear option has the potential to result in a substantially greater impact on Applicant's customers not only in the short run, but also on a long run basis.

As a part of its report, Touche Ross & Company set forth a section which estimates the impact on Applicant's customers resulting from its low case capital cost projections for the rest of this decade. The Staff's consultant concluded that if Black Fox Construction Work in Progress is allowed, Applicant's customers will experience an increase in rates of 110% between now and 1990 and an overall increase of 159% when the first unit is placed in service in 1991. If the Black Fox were constructed on an AFUDC basis, the overall increase would be 306% to P.S.O.'s ratepayers when the first unit is placed in service in 1991. We must point out that Touche Ross & Company assumed that construction of plants could be achieved as scheduled by the Company and did not have the benefit of Management Analysis Company's conclusion that Applicant has only a 10% probability that Unit 1 can be completed by 1991. Mr. Flaherty of Touche Ross & Company testified as mentioned above that the cost estimate which they have submitted should be escalated at $1.06 billion for one year of slippage in the construction schedule. Based upon the testimony presented to us, we conclude that the construction of a nuclear plant will have a substantially greater impact on Applicant's customers in the short run than the construction of a coal plant, and in the long run, because of the risks and uncertainties we discuss herein,the construction of a nuclear plant has the potential to impact Public Service Company's customers substantially more than the construction and operation of a coal plant over the lives of the respective projects.

d. Economic Viability

As reflected above, Staff's consultant, Touche Ross & Company, based its studies for a nuclear project on a generic basis tailored to the capacity planned for Black Fox with in-service dates of 1991 and 1993. It was not until during the hearing that the testimony of Management Analysis Company became available and it became evident based upon project specific information that the Company has only a 10% possibility of constructing the Black Fox project in their planning time frame. Mr. Stratton took Management Analysis Company cost estimate for nuclear construction and Black and Veatch's construction estimate for equivalent coal capacity, computed the thirty year levelized bus bar costs, and concluded that the bus bar costs for coal capacity placed in service in the 1991 to 1994 time frame would be 240 mills while the levelized bus bar costs for the nuclear project within service dates of 1993 and 1995 would be 237 mills. These cost projections are comparable to the testimony of Mr. Sam Rhodes of Touche Ross & Company who advised us that on a thirty year levelized bus bar basis, nuclear capacity would have a slight advantage over coal capacity. We believe that two factors must be recognized as we consider these cost projections.

First, the construction costs utilized by Mr. Stratton are the most optimistic costs of all of the cost estimates and projections submitted into this record by any witness, and Mr. Rhodes thirty-year levelized bus bar cost projection was based upon his firm's low-case projections as reflected in this record. On a thirty-year levelized bus bar cost basis then, an increase in nuclear construction costs whether caused by delay or otherwise would shift the equation in favor of coal. Any significant increase in the cost of nuclear plant construction would clearly destroy the economic viability of this fuel source as a feasible alternative.

The second factor which we must consider in analyzing the levelized bus bar costs, which we have before us, is the likelihood ofcompleting the construction of Black Fox as a nuclear facility in the 1993 and 1995 time frame. Mr. Kent R. Brown, of Management Analysis Company, testified that his firm evaluated the Black Fox station cost and schedule using probabilistic and comparative analysis techniques. In developing its probabilistic and comparable analysis, Management Analysis Company arrived at the conclusion that the Black Fox project had a 50% probability of being completed on the 1993 and 1995 in-service date basis. The study disregarded the effects of a significant nuclear incident such as was experienced at Three Mile Island and which could cause a substantial delay in the ultimate in-service dates of the two nuclear units. In essence, on a probabilistic basis, there is a 50% to 50% chance that Public Service Company can complete the Black Fox project in the 1993 and 1995 time frame. If the coin flips the wrong way so that in-service dates are slipped beyond those years, even the optomistic numbers presented to us by the Applicant and by Staff's consultant will give an economic advantage to coal.

Without regard to the economic cost comparisons presented to us between nuclear and coal generating capacity and even assuming that nuclear power has an economic advantage over coal, several factors tell us that Public Service Company, Western Farmers Electric Cooperative, and Associated Electric Cooperative should not proceed with this project.

At the outset nuclear energy is regulated exclusively at the federal level. Thus, the entire industry is at the mercy of the attitude of the administration in office. Between now and the proposed in-service dates for the Black Fox units, we will have at least three general elections with three potential changes in nuclear energy policy. We have already experienced the impact of a federal government unwilling or unable to reach timely decisions in the areas of standards and licensing of nuclear generating plants.

Because regulation of nuclear power plants is vested exclusively at the federal level, this fuel supply is plagued by additional risks even after a nuclear plant is constructed. A problem at one power plant could cause a shut down order to be issued to all plants of similar design. Thus, a utility with a nuclear plant may suffer loss of capacity because of another utility's problem. We believe that Oklahoma ratepayers are entitled to have the most reliable generation capacity possible.

The evidence in this case establishes that the Black Fox construction project faces construction, financial, regulatory and political risks, each of which impact the capital costs and construction scheduling associated with this project. Taking these risks into consideration, together with the cost projections presented to us by Public Service Company, the Commission Staff and the Consumer Intervenors, we conclude that the Black Fox Nuclear Power Station project is no longer economically viable; that Construction Work in Progress for this project should not be allowed in Applicant's rate base; and that expenditures made from and after the date of this Order in the furtherance of the Black Fox project, will be considered by us to be imprudently undertaken for Oklahoma jurisdiction ratemaking purposes; not only as those future investments might be made by Applicant, but also as those investments may be made by Western Farmers Electric Cooperative and Associated Electric Cooperative and charged to their respective distribution cooperatives through their purchased power adjustment clause. Applicant and its co-owners should take immediate steps to cancel this project so that losses in connection with this project can be minimized. In reaching this conclusion, we recognize that the decision to construct or to continue to construct an electric generating station is a decision which under Oklahoma law rests exclusively with management of our electric utilities. At the same time however, this Commission can and will continue to protect Oklahoma ratepayers from imprudent management decisions.

3. Prudence in Retrospect

Applicant's witnesses were subjected to intensive cross examination by the parties in this proceeding in an effort to determine whether at any time during the course of the history of this project, Public Service Company had acted imprudently either in the initial undertaking or in a failure to discontinue the project at any time thereafter until September 1, 1981.

Staff witnesses from Touche Ross & Company unanimously testified that in their judgment management was prudent in its efforts with the project from inception to the current time. Neal H. Talbot of Energy Systems Research Group testified that the traditional measurements of management prudence no longer apply; he concluded that in his judgment, the Applicant's management has yet to come to grips with the risks and uncertainties which nuclear power faces. In evaluating the testimony and evidence presented to us, as it relates to the prudence of management, our vision must not be distorted by the fact that hindsight has 20-20 vision. In making our determination with respect to prudence, we must judge management's decisions from the perspective of what was known or reasonably should have been known by management at the time those decisions were made. Mr. Talbot's conclusions concerning management having failed to come to grips with the risks and uncertainties of nuclear power could, in our judgment, be applied to the industry as a whole.

At the time Public Service Company decided to construct a nuclear plant a shortage of natural gas was perceived to exist in this country. Based upon this perception, management concluded that in order to mantain reliable capacity it would be necessary to diversify its fuel mix. Simultaneously, there were environmental concerns facing the construction of coal plants which had to be addressed if an electric utility were to construct coal fired generation. The federal government was actively promoting nuclear energy for electric generation and the nuclear option thus looked very attractive to management when it was first considering its options. Nuclear energy, of course, was not without problems, a few of which were safety, waste disposal and decommissioning. In weighing these factors, management elected to diversify into both coal and nuclear generation. The Arab Oil Embargo escallated the price of natural gas emphasized dramatically our need to utilize other sources of boiler fuel. In recognition of this factor together with the perceived shortage of natural gas Congress enacted the Power Plant and Industrial Fuel Use Act of 1978. This legislation, as initially enacted substanially increased the need for Oklahoma utilities to diversify their boiler fuels. The federal government was still energetically promoting nuclear power, and it appeared that management had correctly decided to diversify its fuel mix.

When the accident at Three Mile Island occurred, the nuclear industry was faced with a period of profound uncertainty. It has been argued that at this time management should have known that the risks associated with nuclear power were so severe as to require management to cancel Black Fox immediately. But we must remember that the federal government had been actively encouraging the use of nuclear energy, and it was not unreasonable for management to assume that once the Three Mile Island incident had been investigated the federal government would return to its previous supportive position. The federal government, however, and the Nuclear Regulatory Commission in particular, was dilatory in its resolution of the issues raised by incident and now, nearly three years later, that agency has yet to issue a new construction permit.

Applicant could have better controlled its destiny if the federal government had been more willing to define its policy in a timely fashion. No such expression of direction was forthcoming, and with the passage of time the industry experienced a de facto moratorium on new construction. Recognizing this moratorium to exist, P.S.O. management then reverted to a caretaker status to minimize expenses on the project while preserving its already substantial investment. Without specific direction from the Nuclear Regulatory Commission concerning the future of nuclear energy and the Black Fox project in particular, and in view of the partnership relationship which Applicant has with its coowners, we do not believe P.S.O. acted imprudently in assuming a caretaker status for this project.

When the decisions of management are viewed as we have done from the perspective of the time in which those decisions were made, we believe that Applicant's decisions concerning this project were appropriate. The fact that different people would have, could have, or did reach differing conclusions does not render the decisions of this company imprudent. Accordingly, we conclude that we should provide this Applicant, with our evaluation of the capital recovery treatment which should be given in the event a timely decision is reached to cancel this project.

C. CAPITAL RECOVERY

The parties to this proceeding represent widely divergent positions concerning whether this company should be allowed to recover, its investment in the Black Fox Station project if the project is cancelled. The Attorney General for the State of Oklahoma advises:

> "As for allowing the Applicant to recover roughly $200 million worth of Black Fox investment, this Intervenor feels the recovery at the expense of the ratepayer is unwarranted . . . . It has been P.S.O.'s decision all along and as such,

they should bear the losses associated therewith." (Atty. Gen. Proposed Findings, pp. 40, 42)

The Coalition for Fair Utility Rates advises that this Commission should not make any allowance for a write-off of this investment through rate base, although this group recognizes our duty to insure the financial soundness of the utilities we regulate (Proposed Findings of the Coalition For Fair Utility Rates, p. 4). The Sierra Club, Oklahoma Chapter, urges us to adopt the risk sharing concept proposed by Touche Ross & Company for the Commission Staff. The Staff's proposal, in essence, is that both the stockholder and the ratepayers should share in the write-off of this investment in such a way that the company can maintain its economic viability while minimizing the impact to the fullest extent possible on P.S.O.'s ratepayers. Finally, Applicant urges us to grant a full return on a write-off of this investment, or at least a return on equity equivalent to its current dividend rate.

A public utility company is not permitted to enjoy the full fruits of its business successes inasmuch as regulation prohibits a return higher than that which is required to attract capital and provide service at reasonable rates. As a result, it does not have the resources available to absorb the major adversities which it encounters. In the event that Public Service Company and its co-owners conclude not to proceed with the construction of the Black Fox project, as a nuclear facility, and in view of management's prudence which we have found to exist to this point in the history of the project, we conclude that some mechanism for recovery of the investment in this project which would be written off must be recognized. To do otherwise, that is, to refuse to allow Applicant a mechanism for recovery of the extraordinary loss associated with this project would result in this Company immediately experiencing negative retained earnings for several years. The possibility exists that the Applicant would be placed in receivership. We take judicial notice of the fact that bankruptcy would result in the immediate escallation of a utility's embedded cost of debt to current interest rate levels. The evidence establishes Applicant's long term debt at test year end to be approximately $503 million with a cost rate of 9.114%. Assuming a current interest rate of 15%, bankruptcy would require the customers of the company to pay nearly $30 million more per year just to cover the added interest costs. The utility would immediately lose its credit rating and its access to the capital market. In our judgment the quality of service now experienced by the company's ratepayers would deteriorate rapidly, and the costs to Oklahoma ratepayers of restoring this company to financial health would be substantially greater than the costs associated with a recovery of this investment. In making his recommendation we do not believe the Attorney General intends this result.

Our decision to recommend against proceedings with the Black Fox Nuclear Project was made in large part because we could not subject the customers of P.S.O. to the substantial risks and uncertainties attendant to this project. Similarly, we cannot assign to the Company's ratepayees the profound risks of a bankrupt utility unable to meet its obligations.

Bankruptcy is not a viable option. The evidence in this case establishes and our independent search confirms that there is no standard treatment for abandonment of a plant such as this in the United States. Short of requiring the Company to absorb such a loss below the line, two viable capital recovery alternative scenarios are available to us: full recovery of the loss or some sharing of the costs of the write-off between the stockholders and the customers of the utility.

Applicant, as reflected above and as we have recognized, has demonstrated a need for new generation capacity on its system. A portion of the investment in the Black Fox project could be converted for use in conjunction with a coal fired facility at the Inola site.

To the extent that investment in the site can be utilized for a coal fired facility, Applicant should be allowed to continue to carry this amount as Construction Work in Progress associated with a coal fired facility under normal utility construction accounting principles, and this amount should be excluded from any recovery associated with the Black Fox project. We believe that all advertising expenses and public relations expenses associated with this project should be excluded in calculating the investment in the project to be amortized and recovered.

Applicant should exercise due diligence in securing the sale of equipment, materials and supplies charged to the Black Fox work order and which cannot be used in a conversion of the facility with the proceeds of such sales being credited to the recoverableamount. Equipment which can be utilized elsewhere on Applicant's system should also be deducted from the amount to be recovered.

From an accounting standpoint this amortization would amount to an extraordinary loss which has accumulated over the life of the project. Accordingly, all extraordinary gains realized by the Applicant from 1974 to the date of this Order should be credited against the equity portion of the initial balance of the recovery associated with of this project including such items as the fuel oil profit mentioned in Part II of this Order, the gain realized by the Applicant in connection with its oil and gas lease sale, the gain realized by Applicant in the sale of its building in Tulsa and the tax advantage realized by Applicant in connection with its donation of certain land along the Arkansas River. After deduction of these items from the Black Fox work order, we believe Applicant should be allowed to amortize the initial balance for recovery on a straight-line basis over a ten year period, subject to our further findings as stated below.

A substantial amount of testimony was presented to us with respect to whether or not a return on the recovery portion during amortization should be granted and, if so, how much return should be allowed. We conclude, based upon the testimony presented to us, that a full return would reward the equity owner unnecessarily, while no return on this capital investment would tell bondholders and preferred stockholders that they are not protected from risks which are normally attributable to equity holders of a company. We believe that capital recovery is essential to the financial health of Public Service Company and it is imperative that the investment community retain confidence in this Company. Accordingly, we find that the debt and preferred portion amortized loss associated with a Black Fox recovery should carry their actual costs as established in this case, but that no return be included for the equity portion. Should it become necessary in subsequent rate cases in order to maintain this Company's financial integrity and its ability to attract capital at reasonable cost for the benefit of Oklahoma ratepayers we will consider among other things a partial return to the equity holder.

Applicant has proposed several revenue streams which could be targeted for the write-off of Black Fox nuclear losses. We believe it appropriate to credit any extraordinary gains from Applicant's Oklahoma exploration program and any net revenues derived from Applicant's retained interests in the oil and gas leases sold in 1981. We do not believe that net revenues from off system sales of Applicant's gas should be utilized to realize this recovery because of contingencies associated with that revenue stream. One hundred percent of those revenues should continue to be credited directly to Applicant's ratepayers as has been done by this Commission in the past.

We believe that all extraordinary gains realized by Applicant during the period of the amortization should be credited against this loss by applying these gains first to the equity component. Additionally, the margin on off-system sales of electricity, to the extent that they exceed those credited to the ratepayer on the basis of the test year level should be credited to the Black Fox amortization in the same manner.

Applicant and its parent, Central and South West Corporation currently have pending before the Securities and Exchange Commission an application to spin up Transok Pipeline Company to the first tier level (File number 70-6616). This Commission, through the Commission Staff, has asserted a beneficial or equitable interest inuring to the Applicant's ratepayers as a result of gas processing operations conducted on the Transok system. To the extent that this interest is quantified by stipulation, settlement or otherwise it should be applied to reduce the debt and preferred portion of the amortized loss.

To the extent that the above captured revenue streams are inadequate to meet the initial balance amortization and annual return requirement for losses associated with this project, the balance should be recovered through a rider on Applicant's tariffs on a class allocated kilowatt hour energy charge basis using Applicant's most recently approved cost of service study. An annual balancing of expected and realized revenues will be made, and any differences after audit by the Commission Staff will be resolved through a recomputed energy charge. An audit shall be conducted annually by the Public Utilities Division of this Commission for the purpose of verifying revenue stream credits and adjusting the rider as necessary to meet the amortization schedule. Full interperiod tax normalization accounting should be used in determining the above recovery

We believe that time is of the essence and that Public Service Company, together with Western Farmers Electric Cooperative and Associated Electric Cooperative, should proceed immediately to make their decision with respect to the future of the Black Fox nuclear project and Applicant should notify this Commission of its decision within thirty days of the day of this Order. In the event Applicant and its co-owners conclude that this project should be cancelled, Public Service Company is directed to file report with this Commission setting forth all of the costs which have been charged to the Black Fox work order and making adjustments thereto to implement the objectives of this Order for the purpose of quantifying any rider which may be necessary to begin the amortization process associated with the extraordinary loss which will occur as a result of that decision.

VII. MISCELLANEOUS

A. INTERVENOR PARTICIPATION

We believe that the intervenor groups and parties, which participated in these proceedings, performed a valuable service and were helpful in rounding out and fully developing the record in this case, a case which may well be one of the most important to come before this Commission in the course of its history to date. In particular, we believe that Mr. Louis W. Bullock, the Attorney for Citizens Action for Safe Energy, Sierra Club Chapter of Oklahoma and the Coalition for Fair Utility Rates and Mr. Neal H. Talbot of Energy Systems Research Group, Inc., each made substantial contributions to the decision making process associated with this case. Pending a resolution by our Supreme Court with respect to the question of this Commission's authority to authorize fees and expenses to be paid to intervenors, we believe Applicant should enter negotiations with these parties to resolve the reasonable fees and expenses to which they are entitled without resort to litigation.

B. CONSERVATION FUND

During the hearings associated with this Cause, Applicant proposed the creation of a conservation fund as a supplemental activity of Public Service Company. Applicant proposed to direct revenues from its fuel related revenue streams at the rate of $100,000 per month during the first year and at the rate of $150,000 per month during the second year to fund the program with an effectiveness review at the end of the second year. The fund-supported conservation initiative would be carried on by a separate group within the company which would have the oversight of a citizen's advisory board for guidance on program directions and applications.

While we cannot at this time support the funding of the program as the Applicant proposes, we are intrigued by the concept and we encourage the Company to continue to consider and investigate creative conservation and assistance programs, especially for those citizens who are financially unable to afford initial investments for conservation of energy.

We encourage the Company's interaction with consumer groups throughout its service territory and the close coordination of company-sponsored conservation and assistance efforts with the programs of local human service and community action agencies. We also believe that this Commission's Conservation Services Department should be involved in the planning and development of the goals and objectives of such a program.

We believe these efforts are long overdue and we urge the Company to establish forthwith an active and energetic commitment to humane and responsible conservation efforts and to develop result-oriented programs and policies toward those ends.

This Commission at later hearings will be pleased to review such programs as are developed, to examine the results, costs and benefits, and to make a determination at that time the ratemaking treatment which is appropriate for company expenditures.

O R D E R

IT IS THEREFORE THE ORDER OF THIS COMMISSION that the relief sought by Applicant in these proceedings, as amended and supplemented, should be granted in accordance with the findings, conclusions and provisions set forth hereinabove and that the relief sought by Applicant, in its pleadings, be denied insofar as that requested relief is inconsistent with the findings, conclusions and provisions of this Order.

IT IS FURTHER ORDERED that Public Service Company of Oklahoma shall file revised and restructured rate schedules reflecting the rate increases granted herein in accordance with the findings, conclusions and provisions of this Order and that such rate increases granted herein shall be implemented after the tariffs associated with such revised and restructured rate schedule have been approved by the Director of the Public Utilities Division for this Commission provided however, that Applicant shall not prorate the revenues granted by virtue of this Order between billing cycles.

DONE AND PERFORMED this 15 day of JANUARY, 1982.

CORPORATION COMMISSION OF OKLAHOMA

Hamp Baker
HAMP BAKER, Chairman

Separate Opinion
BILL DAWSON, Vice Chairman

Norma Eagleton
NORMA EAGLETON, Commissioner

ATTEST:

Berdee S Holt
BERDEE S. HOLT, Secretary

pdm/taw

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA, AN OKLAHOMA CORPORATION, FOR AN ADJUSTMENT IN ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA.	)	CAUSE NO. 27068 ORDER NO. 206560

DAWSON, B., Separate Opinion.

There are many very important issues in this case. But one overshadows all the rest in terms of potential impact on the Oklahoma ratepayer--that is, the question of whether it is prudent for Public Service Company of Oklahoma to continue with its Black Fox nuclear plant program. The evidence in this case has convinced all three Commissioners that the answer to that question should be "No". Differences on other issues seem to pale considerably in light of that unanimous conclusion. That is, I think, as it should be.

However, those differences are themselves important and given those differences, this Commissioner would grant less than half of the total amount allowed today by the majority. I note those differences in the pages that follow.

It may be observed first, however, that in three years plus as Oklahoma Corporation Commissioner, I have had opportunity to express my views at some length on most of the basic policy decision issues involved in this case. Accordingly, it is not necessary to further detail those views here. Brief comments only on this occasion with invitation to refer to my earlier opinions--some designated here and others not--should suffice.

PLANT IN SERVICE

As reflected in the separate opinions, filed by this Commissioner in the two interim hearings in this cause, there still existed, after the interim hearings, some doubt as to whether Northeastern #3 and #4 were used and useful during the applicant's test year. It was this Commissioner's position that the Commission should await the full investigation of the permanent hearing before including these plants in the company's rate base. Having now had the permanent hearing, this Commissioner is of the opinion that the applicant has sufficiently proven that Northeastern #3 was used and useful during the test year and, therefore, applicant should be allowed to earn a return on that plant. The record does not, in my estimation, support a finding that Northeastern #4 was used and useful in serving the Oklahoma jurisdictional load during the test year. This is especially true in light of evidence that GRDA will no longer require the 261MW applicant has been supplying. Nor will the Electric Cooperatives require the 77MW which applicant has planned to supply. The record indicates that applicant would have maintained an adequate reserve margin throughout the test year without Northeastern #4 on line and as a result of the construction of Northeastern #4 will have considerable excess capacity for several years to come.

OFF-SYSTEM SALES OF ELECTRICITY

In this Order, the majority has used an amount for off-system sales of electricity equal to that realized by the company during the test year. This is the normal treatment of such revenues. This Commissioner could support use of this test year amount if the majority were excluding the Northeastern #4 plant from the company rate base. But instead, the ratepayers will be required to pay for the excess capacity of Northeastern #4, which will undoubtedly increase the company's level of off-system sales by as much as twofold but they will receive only the level of off-system sales revenue realized during a test year before the additional plant was available.

It is this type of regulation that has encouraged overbuilding by utilities in the past and results in excessive utility bills for the consumers.

The company will have an additional 450MW of capacity, paid for by the ratepayers, available to sell off-system, but will not be required to account to the ratepayers for the additional revenue which they receive.

COAL STOCKPILE

The record does not support the applicant's request for a 120-day coal supply at 75% capacity. The risks suggested as support for this amount appeared spurious when the sponsoring witness was subjected to cross-examination. This Commissioner can appreciate the need for some "insurance" in the event, however unlikely, of a temporary discontinuance of coal shipments. Accordingly, I could support a 90-day supply at 75% capacity for the Northeastern #3 plant. But, because of my conclusion that Northeastern #4 should not be included in applicant's rate base, I do not think we should allow a coal stockpile to be included in the rate base for that plant.

ADVERTISING AND CONSERVATION

As discussed at length in separate opinions filed in Cause No. 26872 (regarding OG&E's Residential Conservation Service program) and Cause No. 27229 (regarding OG&E's Residential Load Management program), this Commissioner could comfortably support an allowance of funds for advertising and implementation of cost-effective conservation programs. As discussed in the above-mentioned opinions, and more specifically by applicant's witness, Arch Little, the Residential Conservation Services program, as well as other conservation programs, may well fall short of this cost-effective criteria. The granting of advertising dollars considerably in excess of test year expenditures in the hope the the company will employ it appropriately--given only the somewhat hollow threat that a future Commission might not be as kind, if they don't--is not enough. I would allow only the test year amount and call for a further hearing six (6) months hence to determine if an additional amount is warranted--given the actual nature of the advertising being employed and conservation ends to which it is being directed.

INFLATION ADJUSTMENT OR ATTRITION ALLOWANCE

This rate case was presented and tried under the established Commission policy of using an historic test year as a measure of a company's proper expenses and revenues. The attrition allowance proposed by the company would have been an out-of-period adjustment. It would then have been a step toward a future test year. A future test year may, in connection with advanced planning rules, provide a more proper means of regulation, but we should not allow such a drastic policy change in the context of a rate case and without sufficient study.

Commission staff sought to describe its proposed inflation adjustment, which the majority today adopts, as something other than an out-of-period, future test year adjustment. Nevertheless, it would seem to have essentially the same characteristics and, for that reason, should be denied.

I would further note that testimony by rate-of return witnesses indicates that an inflation factor has been built into their recommendations. This adjustment would, in effect, provide the company with a double recovery. Accordingly, I would deny the inflation adjustment.

COST OF SERVICE

Unlike most rate cases where the company provides the only cost of service study, the Commission was fortunate to have presented in this case three such studies using three different methodologies. Each had strengths and weaknesses, as pointed out by various parties. Upon study of the testimony and exhibits, this Commissioner would use, as the proper measure of the cost of service, the mean of the allocation factors presented by the different methodologies--adjusted, where necessary, to avoid any unreasonable results.

This case indicated very clearly the importance of having more than one methodology used for determining the cost of service allocation. This Commissioner would, in future rate cases, have the Commission require applicant to provide allocation studies using at least the three approaches we have seen in this case: 1) Average and excess method with the excess spread using the coincident peak, 2) The average and excess method with the excess spread using the non-coincident peak, and 3) The base intermediate peak methodology.

MUNICIPAL DISCOUNT

The 40% municipal lighting discount has been allowed to municipalities for the operation of their incandescent or their most inefficient lighting fixtures. The discount is contrary to conservation, causes subsidization of this class of customer, and should be disallowed. In a recent OG&E rate case (No. 26782), this Commission allowed 4 years in which to phase out the discount. Nearly 2 years ago, in Cause No. 26669, PSO municipal customers were put on notice that the discount was to be discontinued. Accordingly, I would require a 2-year phase out of this discount by PSO. To require non-benefitting ratepayers to subsidize such service beyond that period is simply unfair.

LURS RATE

The adoption of the Low User Residential Service rate is a good first step on the part of the Commission in providing some relief for low income or low consumption residential ratepayers. This Commissioner concurs in this decision but would note that some refinement of this rate may be suggested by the lifeline case testimony (Cause No. 26965).

CUSTOMER CHARGE

This Commissioner has addressed the issue of customer charges in no less than a dozen separate opinions. (see e.g. Oklahoma Electric Cooperative, Cause No. 27119 and Kay Electric Cooperative, Cause No. 27047) In those opinions, the argument has been made that the customer charge is a monopolistic form of pricing and should not be allowed by this Commission. The customer charge can disproportionately raise the average costs per unit of electricity to small users--amounting to a negative lifeline by making electricity for essential needs more expensive. In that sense the customer charge is very much like declining block rates in that it assures that the more you use, the less you will pay per average unit. The impact of the customer charge is heaviest on the smallest customers who are disproportionately low-income household and senior citizens. As noted in Cookson Hills Electric Cooperative, Cause No. 27296, the use of both a customer charge and a minimum bill, as called for by the majority in this case, will almost certainly cause confusion when a customer tries to determine what he has been charged and why. Rather than the inappropriate customer charge, or the confusing combination of customer charge and minimum bill, this Commissioner believes that the Order should approve what the record must clearly support --that is, a minimum bill of no more than \$3.31.

MISCELLANEOUS

This Commissioner would not not allow inclusion of expenditures for leased automobiles and covered parking, research projects, or legal fees for Mr. William Anderson insomuch as no evidence was provided to indicate that these investments were necessary, or even directly related to the rendition of electric service.

This Commissioner would also disallow the requested return for interest expense on customer deposits, for the reason and as argued by the Attorney General in his Proposed Findings of Fact.

RATE OF RETURN

It is usually assumed that the rate of return required by a public utility is determined by the risk of investment as perceived by the investment community. The Commission must allow a rate of return that will attract investors given their perception of the risk of that investment.

Testimony supporting the 16% return on equity allowed by the majority was presented in the case before us. That same testimony pointed to an on-going nuclear project as being the causative factor of the need for that level of return. With this Order, the Commission seeks to relieve the company of that financial drain while providing a rate of return necessary to compensate the company for any detrimental affect the project has had on their financial condition.

If today's Order were one calling for continuation of the Black Fox project or one for only partial recovery of Black Fox expenditures, a 16% return on equity would clearly be substantiated by the record. But where, as in this case, the Order is one that essentially directs applicant to get out of the nuclear plant business while providing for substantial recovery of investment to date, a 16% return on equity is higher than the record would call for. The Commission with today's Order is retroactively and prospectively removing the risk normally associated with a major investment of the kind the company has made. Given such treatment the return on equity must be adjusted accordingly. The return on equity allowed should be no more than fifteen percent (15%).

BLACK FOX

Capacity Needs

It is this Commissioner's position that the record is not complete as to the need for additional capacity. Before this type of analysis can be performed the Commission will need substantial advanced planning capabilities--encompassing adequate forecasting methodologies. It is dangerous to rely on a single forecast such as the time trending model used by PSO. It would seem more appropriate to require the company to either perform or supply the data base necessary to perform econometric and end-use models as well. Therefore, without adequate advanced planning, this Commissioner thinks it highly inappropriate for the Commission to make specific declarations regarding the applicant's future capacity needs. Such declarations are dangerously premature when based on the record in this case only.

Prudency of Past Expenditures

The record in this case suggests to this Commissioner two levels of possible imprudence by the applicant.

On a general level, the record suggests that Applicant ignored or disregarded the numerous signs which should have called for a risk analysis of the project. When--in 1980--PSO sought authority in Cause No. 26824 to create, issue and sell securities, this Commission stated in its Order that it was unwilling to approve and allow refinancing for any new program for which necessary construction permits had not issued, need had not been established and satisfactory economic justification had not been presented.

Since that bond issuance case there have been many nuclear plants canceled for various reasons. We have seen the nuclear industry facing a plethora of problems such as the Three Mile Island accident, the WPPS financial problems and the Diablo Canyon Station engineering difficulties.

In the face of these signals, however, the applicant felt no need to analyze the financial risk of correcting construction errors in plants. No study was conducted of the Nuclear Regulatory Commission's retrofit requirements for nuclear projects. No study was conducted to determine a solution for nuclear waste disposal problems. The record leaves one with the question of whether any risk analyses were performed at all. It is difficult to review the history of developments revolving around the Black Fox project and still find that applicant has acted prudently throughout in its planning for Black Fox Station.

More specifically, testimony by Mr. Will Stratton revealed that as early as fall of 1980, Applicant had information which indicated a cost for Black Fox on the order of $6 billion. It was explained that this was a generic study and not directed specifically at the Black Fox plant. This study, apparently, did not suggest to applicant the need for such a specific study to determine its economic viability. Rather than spend the estimated $500,000 to conduct such a study, applicant chose to spend approximately $3 million a month maintaining its project on a "survival mode". At least, and particularly as to the $40 million plus that has been invested by the applicant on the Black Fox project since the fall of 1980, this Commissioner is unable to join the majority in finding that said expenditure has been prudently made.

Capital Recovery

While this Commissioner finds support in the record for allowing the recovery of some expenditures for Black Fox Station, this is, I feel, the wrong time for the Commission to address such.

To date, the company has pursued its nuclear plans without fully including its ratepayers in the costly decision. Now that the woes resulting from that decision are manifest, they ask the Commission to obligate the ratepayers for a substantial recovery of expenditures without assurances first being given that they will not further drag the ratepayers into the problem.

This Commissioner would submit that before any recovery is finally considered, applicant should first be required to (1) withdraw its N.E.C. application and unequivocally announce the abandonment of the nuclear plant, (2) provide an accounting of all revenue streams dedicated to this project, and (3) either determine that the partners in the project will relinquish all claims against PSO or provide that ratepayers will not be liable for any such claims. I think my colleagues place the cart before the horse with their pre-commitment to allowance and amortization of Black Fox expenses; but, at least, in conditioning the same on official declaration of abandonment of that project by the company they provide some safeguard for the public.

Except as outlined above I concur with the majority as regards the Order today entered.

DONE AND PERFORMED THIS 15th day of January, 1982.

Bill Dawson

BILL DAWSON, Vice Chairman

ATTEST:

Berdee S. Holt

BERDEE S. HOLT, Secretary

cjg

NEWS FROM PSO

P.O. BOX 201, TULSA, OKLAHOMA 74102

AC 918 583-3611

FOR RELEASE: Immediate

FOR FURTHER INFORMATION

CONTACT: Dan Manley
599-2728

LONG-AWAITED RATE ORDER RECEIVED

The $79.1 million rate increase allowed by the Oklahoma Corporation Commission is a long-awaited step toward obtaining rates that reflect cost increases over the last five years, Public Service Company of Oklahoma President R. O. Newman said today.

"PSO's total request was $139.5 million, meaning the Commission has now allowed us just a little over half of our original request," Newman said, pointing out the final order gives the Company only $14 million more than the $65 million already being collected in interim rate increases.

The original request was filed more than a year-and-a-half ago, and PSO's chief executive pointed out the Commission has made no allowances for inflation's effect on the Company during the agency's lengthy hearing process.

As approved by the OCC, the new rates will raise an average residential customer's summer bill approximately $3.63 for 800 kilowatt-hours a month over present interim rates. The residential rate includes a $4.50 monthly customer charge and an $8.00 minimum bill.

"An average customer will notice a slight decrease in the first winter bills because the interim rates were not seasonally adjusted," Newman said.

A customer using 800 KWH this month will pay 49 cents less than last month for the same number of kilowatt-hours.

(more)

With this new rate schedule we are introducing a Limited Usage Residential Service (LURS) rate for customers using less than 400 KWH a month. This should help those lower-income people whose minimal electric use doesn't pose a great burden to our system," Newman commented.

The OCC order, the first general rate increase in six years for PSO, recognizes Northeastern Station units 3 and 4, the Company's two coal-fired generating stations, for the first time in the permanent rate base, although both units have been in operation for some time.

"These modern coal units have provided needed power during some of Oklahoma's most miserable summer days and nights. The record electric usage of our customers had shown the need for these plants long before the Commission began hearings last September," Newman said.

The two units provide 900,000 kilowatts of generating capability, or 24.1 percent of PSO's total system capability. Unit 3 went into commercial operation in December 1979; Unit 4 in September 1980.

The Commission did not allow adjustments for increased costs due to inflation during the time the case was in the hands of the OCC, meaning the new rates reflect the cost of doing business during the test year ending October 1980 -- some 15 months ago.

"Again, PSO finds itself a day late and a dollar short, or, more accurately, two years late and millions short," Newman said.

"To meet the needs of a progressive service area, we must have progressive regulation. PSO needs to have rates which reflect current costs as much as possible.

"Past and, unfortunately, present Commission policy will always find Oklahoma utilities trying to meet today's expenses with yesterday's rates," Newman said.

(more)

The Commission denied PSO's request for rate base treatment of the construction investment for the Black Fox Nuclear Project. The Commission proposed instead that the project be converted to coal, and indicated that if this were done that full recovery of the nuclear investment net of salvage recoveries, but including cancellation and termination costs which might be incurred would be allowed over a 10 year period. The amount to be recovered would be offset by the gain realized by PSO on a recent sale of oil and gas properties. PSO has 30 days to respond to the Commission's invitation to convert the project. PSO will consult with the co-owners of the Black Fox Project before responding to the Commission.

pso

011582

Office of the Federal Register, pursuant to 1 CFR 8.2 hereby removes from the Code of Federal Regulations Title 6, Chapter VI, Assistant Secretary for Administration, Department of the Treasury, consisting of Part 602, and Chapter VII, Council on Wage and Price Stability, consisting of Parts 701 through 704 inclusive.

Title 6, Code of Federal Regulations is hereby vacated.

BILLING CODE 1505-02-M

NUCLEAR REGULATORY COMMISSION

10 CFR Parts 2 and 50

Licensing Requirements for Pending Construction Permit and Manufacturing License Applications

AGENCY: Nuclear Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Nuclear Regulatory Commission is adding to its power reactor safety regulations a set of licensing requirements applicable only to construction permit and manufacturing license applications pending at the effective date of this rule. The requirements stem from the Commission's ongoing effort to apply the lessons learned from the accident at Three Mile Island to power plant licensing. Each applicant covered by this rule must meet these requirements in order to obtain a permit or manufacturing license.

EFFECTIVE DATE: February 16, 1982.

FOR FURTHER INFORMATION CONTACT: Robert A. Purple, Deputy Director, Division of Licensing, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555. Telephone: (301) 492-7980.

SUPPLEMENTARY INFORMATION:

Background of the Rulemaking

The events leading up to the promulgation of this rule were discussed in detail in the Notice of Proposed Rulemaking, which appeared in the **Federal Register** on October 2, 1980, at pages 65247-65248. In that notice, the Commission reviewed some of the actions it had already taken in response to the accident at Three Mile Island and outlined the options it was considering with regard to the review of construction permit and manufacturing license applications. The Commission proposed to resume licensing using pre-TMI requirements augmented as necessary by new requirements identified in the Commission's TMI Action Plan, NUREG-0660. In connection with a request for public comments on these new requirements, the Commission noted that final rules might be issued on some or all of the matters discussed in that notice.

The Commission held a series of meetings regarding this proposed rule in January, February, and March of 1981. At its March 12 meeting the Commission decided that a further brief period of public comment was desirable prior to promulgation of a final rule to ensure that all interested persons have an opportunity to review the contents of the proposed rule and, in particular, have the opportunity to comment on the applicability of the proposed rule to the pending manufacturing license application. The additional comment period was discussed and noticed in the **Federal Register** on March 23, 1981 at pages 18045-18049.

The Commission particularly desired comment on whether or not the pending manufacturing license application, filed by Offshore Power Systems, Inc., should be covered by the proposed rule. At issue is whether the rule's requirements for the capacity of containments to withstand the effects of accident-generated hydrogen are sufficient when applied to floating nuclear power plants.

Analysis of Public Comments

The comments that were received and the Commission's responses are presented below in two parts. The first part addresses the comments received in response to the **Federal Register** Notice of October 2, 1980, regarding the proposed requirements set forth in draft NUREG-0718. The second part addresses comments responding to the March 23, 1981 notice containing the proposed requirements, as modified after consideration of comments, in the form of a proposed rule.

I. Comments to FR Notice of October 2, 1980. Comments were received from:

- C. W. Rowley, Sand Springs, Oklahoma (Rowley)
- Department of the Interior (USDI)
- Marvin I. Lewis, Philadelphia, Pennsylvania (Lewis)
- Bechtel Power Corporation, San Francisco, California (Bechtel)
- Lowenstein, Newman, Reis, Axelrad & Toll (Lowenstein)
- Offshore Power Systems (OPS)
- Public Service Company of Oklahoma (PSO)
- Boston Edison Company (BEC)
- General Electric Company (GE)
- Westinghouse Electric Corporation (*W*)
- Portland General Electric Company (PGE)
- Duke Power Company (Duke)
- Combustion Engineering (CE)

The Commission's consideration of the comments received are reflected in part by revised text in the pertinent sections of NUREG-0718 and in part by the following discussion. The comments are grouped in five areas as indicated below and are referenced by the use of the abbreviations indicated above.

Comments on Proposed Requirements in NUREG-0718

The following is a discussion of comments received on specific NUREG-0660 items for which draft NUREG-0718 proposed requirements applicable to the pending applications.

I.B.1.1—*Organization and Management Long Term Improvements (PSO).*

II.J.3.1—*Management for Design and Construction (PSO).*

The commentor notes that there is an industry-wide effort related to these activities.

Discussion

The Commission is not entirely certain to what specific activity the commentor is referring. Liaison is maintained with the Institute for Nuclear Power Operations (INPO) which is in the process of conducting utility management audits using its own guidelines.

The classification of Action Plan Item I.B.1.1 has been changed to Category 2 (i.e., an item that is to be addressed at the operating license review stage rather than at the construction permit review stage) since it deals with operations management. The discussion that follows addresses the comments with respect to guidance availability.

Although the NRC is developing guidelines for utility organization and management for operations (I.B.1.1), and design and construction (II.J.3.1), the NRC is still required to make a finding on management and organizational capability prior to issuance of a construction permit or operating license, even if approved guidelines are not available. Therefore, as has always been the case, applicants are required to describe their organizational structure and management for design and construction, regardless of whether or not an industry approach is available or is being developed. For example, in the NRC reviews of utility management and organization for recently issued operating licenses, each one has been evaluated on a case-by-case basis. In conducting these reviews, the draft document "Guidelines for Utilities Management Structure and Technical Resources," NUREG-0731, which has been issued for public comment, was used.

The commentor also stated that NRC has ignored design and construction management guidance in response to Action Plan II.J.3.1. This is not the case. Draft guidelines for this task were prepared and have been circulated for internal comment. The guidance will be included in the final version of NUREG-0731 or in a separate document.

I.C.9—*Long-Term Program Plan for Upgrading of Procedures (PSO).*

A commentor noted that it would be difficult to describe in any significant detail, until after January 1982, the extent to which that commentor's program will be coordinated with INPO activities.

Discussion

In consideration of the comment the Commission has modified this requirement, which called for applicants to describe how their program would be coordinated with INPO activities. The modification requires that applicants ensure coordination, to the extent possible, of their program with INPO and other industry efforts.

I.D.2—*Plant Safety Parameter Display Console (Bechtel).*

The commentor suggested adding a reference to the document where the pertinent staff criteria can be found.

Discussion

Reference to NUREG-0696 has been incorporated in NUREG-0718 as suggested.

I.D.4—*Control Room Design Standard* (Bechtel, BEC).

The commentor noted that the IEEE standard reference in the requirement is not yet available.

Discussion

The Commission has reconsidered this proposed requirement and has placed this Action Item in Category 1 (i.e., an item that is not applicable to the construction permit review). However, the need was found to strengthen the I.D.1 requirement governing control room design revisions. I.D.1 places general requirements on the ML and CP applicants.

I.E.4—*Coordination of Licensee, Industry and Regulatory Programs* (PSO). The commentor objected to describing, prior to issuance of a CP, efforts to evaluate and factor in applicable experience at similar plants on the gounds that the Nuclear Safety Analysis Center (NSAC) is developing a generic industry plan and that a separate response by the utility could undermine the generic industry program.

Discussion

The Commission considers it important that those responsible for the design and construction of nuclear plants have a program in place prior to issuance of a CP or ML (even if that program is later superseded by an industry program) that assures an early awareness of safety problem areas and areas of safety improvements that arise elsewhere. The Commission would have no objection if a utility were to improve such a plan at a later date by adopting a plan worked out generically between the industry and the NRC staff. The requirements of I.E.4 are covered by I.C.5.

II.A.2—*Site Evaluation of Existing Facilities* (USDI, Lewis, Bechtel, Lowenstein, PSO, BEC, CE).

Siting was one of the four areas that the Commission identified in the October 2, 1980 notice of proposed rulemaking as deserving special attention. Several comments (Bechtel, Lowenstein, PSO and BEC) cited Section 108(b) of Pub. L. 96-295 (NRC FY 80 Authorization) and express or imply concern that the proposed requirements under II.A.2 are not consistent with exemption from future regulations that are to be promulgated under Section 108.

Discussion

The Commission believes that the proposed requirements would not have been inconsistent with Section 108. However, based on preliminary staff evaluation of the sites involved, as well as the requirement added in II.B.8 for each CP applicant to perform a plant/site specific probabilistic risk analysis, the Commission has reclassified II.A.2 to Category 1.

The USDI and Lewis comments are addressed elsewhere in this document under the discussion of comments on the methods of implementing the requirements.

II.B.1—*Reactor Coolant System Vents (Bechtel).*

The commentor suggested that this item be removed since II.B.8 requires applicants to describe the degree of design conformance with the proposed interim requirements.

Discussion

Since the proposed interim rule, related to hydrogen control and degraded core considerations, as published in the **Federal Register** (45 FR 65466, October 2, 1980), did not include a requirement to demonstrate by analysis that direct venting will not result in violations of combustible gas concentration limits, II.B.1 has been revised to eliminate the requirement.

II.B.8—*Rulemaking Proceeding on Degraded Core Accidents (Bechtel; PEC; Lewis; Lowenstein; OPS; PSO; W; CE).*

Most comments received opposed requiring any concrete actions in the area of accommodating degraded-core accidents on the part of the applicants prior to completion of the rulemaking process. Several commentors noted that the requirement in this area, as expressed in the draft NUREG-0718, was too openended and did not clearly set forth acceptance criteria.

Discussion

Degraded core rulemaking was another of the four areas the Commission identified in the October 2, 1980, **Federal Register** notice as deserving special attention. As the rule was drafted in that notice, the applicants would have been required to describe the extent to which their designs conform to the proposed interim hydrogen control rule and to provide reasonable assurance that issuance of a CP or ML would not foreclose the ability to accommodate potential requirements resulting from the rulemaking proceedings. The Commission also listed some features as potential requirements and proposed that the applicants submit an evaluation of the preventive and mitigative features having a potential for significant risk reductions that they would propose to include at their facilities.

In view of the comments and upon further consideration, the Commission has revised this requirement. The principal objective in the revision has been to take advantage of the fact that, for a plant that has not yet begun construction, it should be relatively easier to avoid foreclosing design modifications resulting from the rulemaking. For some of the potential design requirements that might be required by the final rule, it is relatively easy to ensure that they can be accommodated at any stage of construction (e.g., by providing large containment penetrations to accommodate a filtered vented containment concept). However, to extend this approach to every conceivable rule requirement could easily lead to major redesigns of these plants, for which considerable design has been completed, possibly causing unnecessary delays in their construction. On the other hand, to do nothing at this time would very likely result in foreclosure of the practical implementation of some of the future requirements.

Taking into account the fact that the plants represented by the pending applications are of the most recent design and that the proposed sites are comparatively good sites, the Commission has adopted a policy of allowing construction to proceed while minimizing foreclosure of plant modifications in the structural design area that may result from the rulemaking proceeding on degraded core accidents. Specifically, as reflected in II.B.8, prior to issuance of a CP or ML, the applicants would be required to commit to (1) performing a site/plant probabilistic risk assessment (This risk study would encompass many of the other concerns related to siting, systems reliability, and degraded core accidents), (2) making provisions for one or more containment penetrations for possibly venting the containment, (3) providing hydrogen control measures, and (4) providing preliminary design information sufficient to demonstrate, given a 100 percent fuel clad metal-water reaction accompanied by either hydrogen burning or post-accident inerting, that (a) containment integrity will be maintained at an internal pressure of at least 45 psig, (b) systems necessary to insure containment integrity will perform their intended function, (c) facility design will provide reasonable assurance that uniformly distributed hydrogen concentrations cannot exceed 10 percent (controlled burning) or, in the alternative, the post-accident atmosphere will not support hydrogen combustion, (d) facility design will provide reasonable assurance that hydrogen will not collect in areas where localized concentrations could unintentionally burn or detonate and result in loss of containment integrity or loss of appropriate mitigating features, and (e) inadvertent operation (based on CO_2) post-accident inerting hydrogen control system can be safely accommodated during plant operation.

II.C.4—*Reliability Engineering* (Bechtel; Lowenstein; PSO; W; Duke).

Reliability engineering was one of the four areas that the Commission identified in the October 2, 1980 notice of proposed rule making as deserving special attention.

The commentors generally expressed the view that reliability engineering is an important tool in designing for safety, but felt that, because the methodology is not well developed, it would be inappropriate to require extensive analysis as a prerequisite for a construction permit. Most commentors believed that a commitment to incorporate reliability engineering during final design, after CP issuance, would be appropriate. However, one commentor argued that no requirement in this area should be specified until the degraded core rulemaking is completed.

Discussion

The requirement under II.B.8 in the revised NUREG–0718 to perform an overall plant/site risk study will, in effect, encompass and go beyond the simplified reliability analyses called for in the draft NUREG–0718. The comprehensive risk study is expected to achieve a more thorough evaluation of plant safety and will provide a sounder technical basis for making decisions regarding potential plant improvements. Accordingly, the more limited effort called for in the draft NUREG–0718 has been replaced by the risk study requirement of II.B.8.

II.D.2—*Research on Relief and Safety Valve Test Requirements* (Bechtel, BEC).

The commentor noted that the two entries shown for this item should either be combined or one entry deleted.

Discussion

Action Item II.D.2 has been placed in Category 1 since it deals with research on generic tests. Action Item II.D.1 has been expanded to include the information presently shown in II.D.2.

II.F.3—*Instrumentation for Monitoring Accident Conditions* (Regulatory Guide 1.97) (PSO).

The commentor expressed concern that since Regulatory Guide 1.97 has not been issued, it will be difficult for the utilities to meet the NUREG–0718 requirements in a timely manner.

Discussion

Revision 2 to Regulatory Guide 1.97 was issued on December 24, 1980.

III.A.1—*Improve Licensee Emergency Preparedness—Short Term (BEC, PSO).*

III.A.2—*Improve Licensee Emergency Preparedness—Long Term (BEC, PSO).*

The commentors suggested that the requirements in these two items be combined and noted that the requirements should only represent information submitted at the CP review stage.

Discussion

Item III.A.1.1 in the TMI Action Plan was intended to apply only to operating reactors and certain operating license applicants, not to CP and ML applicants. For CP and ML applicants, the long term item III.A.2 called for licensees to participate in the development of guidance and criteria, which has now been completed. The Commission has issued new regulations to upgrade emergency preparedness planning for NRC–licensed facilities. These new regulations were issued on August 19, 1980, and became effective on November 3, 1980. Since item III.A.2 is now covered by the regulations, it has been removed from NUREG–0718.

Item III.A.1.2 has been revised to provide clearer guidance by specific reference to NUREG–0696.

Special Consideration Areas of Siting, Degraded Core Rulemaking, Reliability Engineering, and Emergency Preparedness

(See the discussion above under II.A.2, II.B.8, II.C.4, and III.A.1.–.2)

Deviations From the Standard Review Plan

Several of the responses commented on the proposed requirements to document deviations from the Standard Review Plan. On October 9, 1980, another Notice of Proposed Rulemaking was published in the **Federal Register** (45 FR 67099) which also detailed requirements for documenting deviations from the SRP. This second notice not only reiterated the documentation requirements of the first notice, but also extended the requirements to operating plants and construction permit holders. A comprehensive final rule which will also include action for the pending CP and ML applications is under consideration in connection with 45 FR 37009. Accordingly, no special requirement on this subject will be included in this rule.

Comments on Instruction to Atomic Safety and Licensing and Appeal Boards (Lowenstein; PSO; BEC)

The notice of proposed rulemaking also requested comments on the extent to which judgments reached by the Commission on siting, emergency preparedness, reliability engineering, degraded core rulemaking, and the requirements of NUREG–0718 should form the basis for instructions to licensing and appeal boards in the CP and ML proceedings.

One commentor (Lowenstein) suggested that the licensing boards should be instructed that strict time schedules are to be imposed and enforced for completion of litigation. The Commission anticipates that licensing boards would, under present authority, impose and enforce appropriate schedules.

With respect to siting, this commentor recommends that the licensing boards be permitted to entertain contentions that any part of additional requirements proposed by the NRC staff as a result of the proposed rule on siting are unnecessary or that such proposed requirements are not being complied with, but that requirements beyond those proposed by the staff may not be entertained and that boards' authority to raise issues *sua-sponte* should be subject to the same limitations. Also, this commentor would have the boards instructed not to entertain contentions that alternate sites be considered due to demographic considerations in view of the provisions of Section 108(b) of the NRC appropriation authorization for Fiscal Year 1980, discussed under item II.A.2 above.

With respect to degraded core rulemaking, the above commentor would have the licensing boards instructed to limit the litigation in a fashion similar to that proposed by this commentor on the siting issue, namely by restricting contentions to the NUREG–0718 requirements applicable to the CP review stage, including the requirement to consider certain preventive and mitigative features.

With respect to reliability engineering, the above commentor would have the licensing boards instructed that they may only entertain contentions on the nature, method of conduct, and completion dates of the studies and the program to assure that the results are reflected in the final design. Here also, this commentor recommends that the authority of licensing boards to raise issues *sua-sponte* be subject to these same limitations.

Another commentor (PSO) believes that the Commission should issue a rule directing licensing boards to resume licensing proceedings in accordance with Option 1 (which the commentor believes would entail further notice and opportunity to comment before implementation). (The options are described in the following section.) If, however, Option 3 is adopted by the Commission, then this commentor would propose that the rule should be issued and made effective within 30 days after publication in the **Federal Register.**

The third commentor (BEC), who also favors Option 1, would have the licensing boards instructed that they may entertain contentions that one or more NUREG–0718 requirements applicable to the CP review stage are not complied with but may not entertain contentions that requirements beyond these are necessary. This commentor would also have the licensing boards' authority to raise issues *sua-sponte* subject to these same limitations.

Discussion

The Commission has decided that Option 3 should be embodied as a rule, to be effective 30 days after publication of the notice in the **Federal Register.** This rule, like other Commission regulations, may be challenged in accordance with 10 CFR 2.758.

Comments on the Method of Implementing the Requirements

In the notice of proposed rulemaking, three options for resuming licensing on the pending CP/ML applications were presented. Briefly, they were as follows:

Option 1

Resume licensing using the pre-TMI requirements augmented by the applicable requirements identified in the Commission's June 16, 1980 Statement of Policy regarding operating licenses.

Option 2

Take no further licensing action until the rulemaking actions described in the Action Plan, NUREG–0660, have been completed.

Option 3

Resume licensing as indicated under Option 1 above, but also require certain additional measures or commitments in selected areas (e.g., those that will be the subject of rulemaking.)

A majority of those commenting favor Option 1 which, with respect to the TMI Action Plan, would, in effect, treat the pending applications as if they were the last of the present generation of nuclear power plants. The applicants for these plants would not, under this option, be required to address the four special areas cited in the notice. Reasons cited for selecting that option include:

Option 3 could significantly delay CP licensing process (Bechtel, PGE)
Option 3 constitutes excessive and unnecesary regulation (Lowenstein) pending CP applicants should be treated like present CP holders (PSO) "additional measures" of Option 3 would be inordinately costly (BSE)
Option 3 proposes a different and escalated set of TMI-related requirements (GE)
Option 3 adds uncertainty to the review process by requiring commitments to future events (CE)
Sufficient "in the interim" and can be implemented in a realistic and cost effective manner (W)
Reduce dependence on foreign oil (Rowley)

One commentor (OPS) suggested that either Option 1 or Option 3 would provide a reasonable basis for resuming licensing.

One commentor (Duke) proposed its affected units (Perkins) be exempted from the rulemaking altogether because those units are intended to be identical to other units (Cherokee) already granted CP's.

One commentor (USDI) recommended that no construction permits be issued until the siting rulemaking has been completed. While it is true that a siting rule is being formulated, it is not expected to be so drastically different from the present guidelines as to make these previously evaluated sites grossly deficient. The Commission therefore declines as a matter of policy to delay consideration of the pending applications for conclusion of the siting rulemaking.

One commentor (Lewis) asserted that any action at this time is unnecessary and/or premature. Among other things the commentor stated that there is no demand or "need for power" from new plants at this time. The Commission finds that those considerations are outside the scope of this rulemaking. Need for power and related issues have been or will be addressed in the individual CP or ML proceedings by the licensing boards. This commentor also stated that many new requirements will eventually be developed in answer to the accident at TMI–2. Included are proposed rule changes on population density, and consideration of "Class 9" accidents. In his view, concurrent consideration of several rulemakings at one time makes for duplicative efforts. However, the comments in this regard overlook the fact that ongoing licensing proceedings are always subject to matters in rulemaking and that applications are in any event judged against current licensing requirements.

On balance, the Commission continues to believe that Option 3, as modified by revisions to II.A.2, II.B.8, and II.C.4, is the most suitable course of action to take.

II. Comments to FR Notice of March 23, 1981. Comments were received from:

1. J. D. Sloan, Charlotte, North Carolina (Sloan)
2. Southern Company Services, Inc., Birmingham, Alabama (SCS)
3. Minnesota Pollution Control Agency, Roseville, Minnesota (MPCA)
4. Offshore Power Systems (OPS)
5. Baltimore Gas and Electric Company (BG&E)
6. Boston Edison Company (Boston Edison)
7. Gilbert Associates, Inc., Reading, Pennsylvania (Gilbert)
8. Town of Hampton Falls, New Hampshire (Hampton Falls)
9. Marty Casella, Sun Valley, California (Casella)
10. Jane J. Estes, Blacksburg, Virginia (Estes)
11. Stone & Webster Engineering Corporation, Boston, Massachusetts (S&W)

12. Atomic Industrial Forum, Washington, D.C. (AIF)
13. Edison Electric Institute, Washington, D.C. (EEI)
14. Virginia Electric and Power Company (VEPCO)
15. Combustion Engineering, Inc., Windsor, Connecticut (CE)
16. Marvin I. Lewis, Philadelphia, Pennsylvania (Lewis)
17. Robert Alexander, Houston, Texas (Alexander)
18. Committee on Nuclear Quality Assurance, American Society of Mechanical Engineers (NQA)
19. Bechtel Power Corporation, San Francisco, California (Bechtel)
20. Consolidated Edison Company of New York (Con Ed)
21. General Electric Company, San Jose, California (GE)
22. Carolina Power & Light Company (CP&L)
24. Florida Power Corporation (FPC)
25. Lowenstein, Newman, Reis & Alexrad (Lowenstein) on behalf of Houston Light & Power Company and Puget Sound Power and Light Company
26. Commonwealth of Massachusetts (Massachusetts)
27. Tampa Electric Company (TEC)
28. Business and Professional People for the Public Interest, Chicago, Illinois (BPI)
30. Westinghouse Electric Corporation, Pittsburgh, Pennsylvania (W)
31. Public Service Company of Oklahoma (PSO)
33. Portland General Electric Company (PGE)
34. Commonwealth Edison Company (CEC)
35. Middle South Services, Inc., New Orleans, Louisiana (MSS)
36. Florida Power & Light Company (FP&L)
37. Central Power and Light Company (Central P&L)
39. Tennessee Valley Authority (TVA)
40. Ebasco Services, Inc., New York, N.Y. (Ebasco)
42. Babcock & Wilcox, Lynchburg, VA (B&W)
43. D. Marrack, Bellaire, Texas (Marrack)

(Letters numbered 23, 29, 32, 38 and 41 are not listed because they are duplicates of the letters numbered 6, 24, 21, 32 and 11, respectively. The letters numbered 1, 6, 9, 10 and 26 contain no comments on the proposed rule).

The staff's consideration of the pertinent comments received is provided in the following discussion. The comments are grouped as indicated below, with the source of the comments referenced by use of the abbreviations indicated above.

1. Inclusion of the ML Application

The following is a discussion of the comments received on including the application for a Manufacturing License (ML) in the rule for licensing requirements for pending applications for Construction Permits and Manufacturing Licenses.

One commentor (Lewis) clearly favors outright exclusion of the ML from the rule. The basis for exclusion presented by the commentor is that Offshore Power Systems lacks a customer for the Floating Nuclear Plant (FNP).

A majority (16) of the (20) commenting letters that address the issue strongly favor including the ML in the rule. Three others (Boston Edison, EEI, Lowenstein) believe the ML should be included, but not if this results in a delay in promulgation of the rule for the CP applications. Some of the reasons given for this support are the standardized plant concept (BG&E, OPS, VEPCO, CON ED, CP&L, FPC), conservation of resources, "diversity of fuel supplies", and "innovation" (BG&E). Also, the considerable expenditure of dollars, expert engineering man-years, and support facility construction are noted.

OPS, particularly, states that exclusion of the ML from the rule would "* * * greatly damage the concept of standardization and would cast substantial doubt on whether the incentives perceived to result from standardization in fact exist." OPS further submits that the investment in the FNP was made "* * * in reliance on our understanding that the standards to be applied to the Manufacturing License are the same as those which apply to Construction Permits, with only such distinctions as are set out in 10 CFR Part 50, Appendix M" and that to segregate them now would "* * * insert * * * a commercial requirement completely at odds with the Manufacturing License concept and the Commission's prior licensing philosophy." OPS asserts that the requirements in Subsection (3)(v) of the proposed rule are "* * * entirely appropriate for application to Floating Nuclear Plants", and that "[D]esign features required by the rule can and will be incorporated into the Floating Nuclear Plant design * * *". OPS also notes that "[M]any of the Near-Term Construction Permit plants utilize containments with volumes and design pressures comparable to the ice condenser containment employed in the Floating Nuclear Plant", and that "* * * information reported at March 1, 1981 ACRS meetings * * * indicate (sic) that the capability to increase containment strength is very nearly the same for the Near-Term Construction Permit plants and the Floating Nuclear Plant * * *."

Discussion for Inclusion of the Manufacturing License in the Rule

The Commission generally agrees with the comments that favor inclusion of the ML application in the rule and has, therefore, included it.

2. Comment Period Too Short

One commentor (Gilbert) stated that, "Based upon the numerous criteria contained in this proposal, and the potential monumental impact of those requirements, the 20-day comment period is too short and restrictive for public rulemaking in spite of the NRC's rationalization of this time interval."

Discussion

The 20-day comment period provided in the notice printed in the **Federal Register** on March 23, 1981 (46 FR 18045) was considered by the Commission to be sufficient, considering the 45-day comment period provided in a previous notice on October 2, 1980 (45 FR 65247). Promulgation of the rule will provide the affected parties with a firm basis for responding to TMI-related requirements, thereby eliminating the present uncertainty and its attendant potential for unnecessary delay.

3. Application of the Proposed Rule to Present CPs and OL Applications

One commentor (BPI) submits that "the new rule, if enacted, should be made applicable to present holders of construction permits, as well as to applicants for construction permits and manufacturing licenses. To decline to so apply the amendment, especially to plants which are in the very early stages of construction, suggests that the Commission is not seriously attempting to implement the needed upgrading of safety for all nuclear plants." Another commentor (Marrack) argues that all plants not yet operating should meet the minimum improved standards.

Discussion

Holders of construction permits have already been informed by letter that they must meet the TMI-related requirements contained in NUREG-0737. There is an ongoing rulemaking to codify these requirements in the Commission's regulations. This action will ensure that the bulk of the requirements that are contained in this new rule for pending CP/ML applicants will be made applicable to all holders of construction permits. For those areas in this new rule that go beyond the requirements of NUREG-0737 (such as those related to containment strengthening and other hydrogen control measures), the Commission, in the near future, intends to consider their applicability to present CP holders on a case-by-case basis.

4. Imposition of New Requirements

One commentor (FPC) urges "the Commission to impose new licensing requirements on plants during the licensing process only after a cost/benefit evaluation has been completed utilizing identified safety benefit compared to financial requirements to implement i.e. containment strength. We have a concern that without such evaluations licensing requirements may be imposed with minimal increase or perhaps no increase in overall safety at significant costs. This will quickly erase the nuclear alternative as viable and severely limit our energy resources." Another commentor (CE) also recommends that any major modifications should undergo complete cost/benefit assessment. In addition, the commentor urges "that this requirement should be coordinated with other rulemaking proceedings in progess, specifically the development of an overall safety goal."

Another commentor (Lowenstein) said, "we also think it essential that the Commission recognize that in many instances applicants have already completed designs, procured equipment, or committed to fabrication of equipment on much of the proposed plants. The Commission should make clear to the NRC staff that the new requirements should be interpreted to minimize extensive redesign and procurement of new equipment to replace that already purchased."

Discussion

The Commission agrees that new requirements should be based on favorable cost/benefit evaluations, but this is not possible, in quantifiable terms, at present due to the lack of a specified safety goal. The Commission and its staff recognize that unnecessary extensive redesign and procurement of new equipment should be avoided. However, in its extensive deliberations concerning TMI-related requirements, the Commission has decided that the requirements in the new rule are necessary for protection of the public and that their costs are not exorbitant. Acceptable alternative methods of meeting the requirements stated in the rule will be considered.

5. Imposing Requirements Now Under Rulemaking

Several commentors (S&W, CEC, Lewis, Ebasco) oppose the imposition of requirements subject to other rulemaking proceedings, particulaly relative to degraded core conditions, as premature.

Another commenter (W) said that "in light of the ongoing generic NRC proceedings with respect to safety goals and methodology, degraded core cooling, siting and emergency planning, the Commission should make it clear that the final rule when adopted is an interim rule to be applied pending the outcome of these proceedings and the risk assessments required by the rule." "Paragraphs (e)(1)(xv), (e)(3)(iii), (e)(3)(iv), (B thru D): Each of these items are either premature impositions of requirements not yet authorized by the NRC or are clearly the subject of current ongoing rulemaking e.g. hydrogen control and degraded core rulemaking. To impose these requirements at the CP stage precludes the full airing of these issues prior to assumption by the applicant of construction costs," stated one commentor (CEC).

Discussion

This rule does include some requirements which are subjects of other ongoing rule-making proceedings. The purpose of including these requirements in this rule is to ensure that future requirements are not rendered impractical because construction has been allowed to proceed on these plants without having made provisions for them.

6. NUREG-0718 Is Premature, Limited and Misleading

One commentor (Lewis) states that "the staff guidance in NUREG-0718 * * * is so limited and so misleading that it will probably be a matter of civil suit between NRC and Licensee's. Many licensee's will be able to argue that the staff guidance mislead them into believing that new requirements would be easy-to-meet and low cost." The commentor therefore, suggested that NUREG-0718 be eliminated.

Discussion

The Commission is not aware of specific additional guidance the commentor would have it provide at this time. The staff will provide applicants with additional guidance as the need arises. Eliminating NUREG-0718 at this time would remove all guidance and could lead to more instability in the review process.

7. Objections to Detail of the CP/ML Rule

Two commentors (Gilbert, CEC) object to the regimentation, "great detail", and "specificity" of placing such a rule in the Code of Federal Regulations. They support the use of Regulatory Guides, Standard Review Plans, and/or various NUREG documents. One commentor (Gilbert) goes on to state: "The current proposal applies to but seven pending applications, yet proposes to more than double the volume of 10 CFR 50.34. Furthermore, a number of the individual requirements are so design specific as to preclude the possibility of alternate designs or solutions in the future. We thus see these new proposed regulations as in conflict with both President Reagan's directive for both simplified regulatory requirements, as well as his stated beliefs that new nuclear plants should not be unduly regulated into oblivion * * * We believe that the general goals and objectives of proposing the new 10 CFR 50.34(e) can be obtained through means other than the new regulations (as has been done on plants undergoing OL review) on a case-by-case or even a generic basis, and that imposing these requirements by use of a new 10 CFR 50.34(e) is unwarranted and without justification."

Discussion

The regulatory authority provided by a rule ensures a clear and concrete way to impose the necessary requirements in the wake of lessons learned from the TMI-2 accident. Separate rules for the CP/ML applicants and the OL applicants will clarify the specific requirements the Commission considers necessary for plants at these stages in the licensing process. Excessive details have been removed from the proposed rule; where details are specified, the Commission has decided they are necessary to ensure the safety of the public.

8. Comments on the Method of Implementing the Requirements

One commentor (PSO) provided comments objecting to Option 3* on the basis of timing, "i.e., this option requires the completion of a myriad of time consuming engineering activities and analyses before issuance of construction permits. On the other hand, Option 1 would have required only that an applicant make necessary commitments, including reasonable implementation schedules, before issuance of the construction permits."

*Option 3 requires certain measures or commitments in selected areas (e.g., those that will be the subject of rulemaking) in addition to those imposed by Option 1. Option 1 is to resume licensing using the pre-TMI requirements augmented by the applicable requirements identified in the Commission's June 16, 1980 Statement of Policy (now replaced by the December 18, 1980 Statement of Policy) regarding operating licenses.

Another commentor (TVA) expressed the belief that the major issues in the proposed rule have not been resolved sufficiently to process final rule changes at this time. TVA suggested the following approach as a more effective means of accomplishing the changes in licensing requirements:

1. Require that all pending construction permit and manufacturing license applicants commit to implement the final rules that grow out of the money pending post-TMI rulemakings, such as probabilistic risk assessment methodology, safety goal, siting, degraded core, etc.

2. Implement only those changes in the proposed rule which have been promulgated and issued for use by the near term operating license plants. For other changes, retain the existing rules pending completion of the post-TMI rulemakings.

Discussion

The Commission has adopted Option 3, which will ensure that approved action items in the TMI Action Plan are applied to the new CPs and ML and will provide for early consideration of these added safety measures so as to minimize the costs of incorporating them into the design of the facility.

9. Comments on Prompt Adoption of the Rule

Many of the commentors (AIF, EEI, Lowenstein, etc.) expressed strong support for the prompt adoption of the rule. One commentor (Boston Edison) submitted "that the Commission would be shirking its vital responsibility in this area if it did not issue a rule such as this and if this rule were not intended as binding upon the Commission's subsidiary boards." Another stated, "C-E agrees with the Commission's intent of defining the set of TMI-related requirements that are both necessary and sufficient to resume NRC review and approval of pending and ML applications. These requirements (as modified to reflect public comments) should therefore be issued expeditiously in conjunction with a clear enunciation of the sufficiency of those requirements, so that NRC staff action on pending applications can recommence."

Discussion

The Commission believes that issuance of the final rule is the proper response to these comments.

10. Basis for Compliance With the Rule

A. One commentor (Bechtel) noted that most of the items contained in the proposed rule reference action plan items in NUREG-0718 and NUREG-0660 and recommended that where the referenced paragraph in these NUREGs amplifies the requirements of the rule, it should be recognized that as an acceptable means of compliance. Another commentor (Ebasco) also pointed out that the proposed rule imposes new requirements in areas where final NRC acceptance criteria have not been finalized and that NRC policy relative to implementation of those criteria must be flexible because of the different types of requirements. To expedite the CP hearing process, Ebasco suggested that "compliance with NUREG-0718 be considered prima facie evidence that TMI requirements have been met."

Discussion

The Commission agrees with the comments. The Commission has reviewed NUREG-0718 and has concluded that the position contained therein can provide a basis for responding to the TMI-2 accident. Applicants may, of course, propose to satisfy the rule's requirements by a method other than detailed in NUREG-0718, but in such cases must provide a basis for determining that the requirements of the rule have been met. NRC acceptance criteria will be sufficiently flexible to permit appropriate alternative methods of meeting the requirements.

B. Two commentors (Boston Edison, Lowenstein) noted that "Some of the provisions of the proposed rule required the applicant to conduct studies and submit them to the NRC for review and appropriate action. Boston Edison pointed out that "these studies will be completed after issuance of the construction permit, in some instances several years later. We believe it is necessary to make clear that the construction permit licensing boards or appeal boards do not retain jurisdiction or supervisory authority over the applicant and NRC staff for the purpose of reviewing the completed studies. This would extend the construction permit proceeding far beyond the actual issuance of the permit and continue needless uncertainty. Issues concerning the required studies are appropriate matters for the operating license stage review." Another commentor (Ebasco) noted that NRC will have received the studies, in some instances, prior to SER issuance for CPs since some of these study requirements were applicable to operating plants and are generic in nature. Ebasco suggested that the studies be excluded from the (CP) hearings.

Discussion

The Commission does not expect its adjudicatory boards to retain jurisdiction or supervisory authority over fulfillment of those requirements for studies to be completed subsequent to issuance of the CP. However, the Commission does expect the staff to review such studies in a timely manner and to take appropriate action. Regarding the Ebasco comment, one of the study requirements has been deleted for the reason suggested.

C. Another commentor (Lowenstein) stated, "It is essential that the Commission make clear that this regulation, along with the existing regulations, establishes an adequate and sufficient response to the Commission's post-TMI requirements. While the notice intimates this on page 18046 (of the FR notice), we urge that it be explicitly stated in the rule."

Discussion

In the Notice of Rulemaking (46 FR 18045) published on March 23, 1981, under Substance of the Rule, the Commission stated, "It is the Commission's view that this new rule, together with the existing regulations, form a set of regulations, conformance with which meets the requirements of the Commission for issuance of a construction permit or manufacturing license." The Commission reaffirms this view with the exception of hydrogen control measures for the manufacturing license, and, to eliminate any ambiguity regarding its intent, is amending its special review procedures in 10 CFR 2.786 to delete the statement in paragraph (e) that compliance with existing regulations may turn out to no longer warrant approval of a license application. However, it should be noted that the Commission also indicated in that notice that some elements in the TMI Action Plan have not been acted upon and thus may be required on the basis of future rulemaking.

11. Additional TMI-Related Requirements

One commentor (MPCA) suggested that additional items of the TMI Action Plan should be incorporated into the rule as CP/ML licensing requirements. The specific items in NUREG-0718 and NUREG-0660 suggested for inclusion in the rule are:

I.A.4.1 Initial Simulator Improvement
I.C.1 Short Term Accident Analyses and Procedures Revision
II.B.4 Training for Mitigating Core Damage
II.B.6 Risk Reduction for Operating Reactors at Sites with High Population Densities
II.B.7 Analysis of Hydrogen Control
II.E.2.1 Reliance on ECCS
II.E.2.3 Uncertainties in Performance Predictions
II.E.3.2 Systems Reliability

II.E.3.3 Coordinated Study of Shutdown Heat Removal
II.J.1.1 Establish a Priority System for Conducting Vendor Inspections
III.D.1.2 Radioactive Gas Management
III.D.1.3 Ventilation System and Radionuclide Adsorber Criteria
III.D.1.4 Radwaste System Design Features to Aid in Accident Recovery and Decontamination
III.D.2.1 Radiological Monitoring of Effluents
III.D.2.3 Liquid Pathway Radiological Control
III.D.2.4 Offsite Dose Measurements

Discussion

The Commission has considered incorporating each of these requirements into the proposed rule, but for the reasons stated below it has determined that none of these should be added.

Items II.E.2.3, III.D.1.2–4, III.D.2.1 and III.D.2.3–4 have been judged lower priority TMI issues as reflected by task initiation dates of FY82 or later. Because of their relative low priority, the Commission believes their incorporation into the CP/ML rule is unnecessary. However, the results and conclusions of these tasks will be appropriately considered during the OL review.

A second group of suggested items is covered in other TMI action tasks that are included as requirements in the proposed rule. Items II.B.6 and II.E.3.2.3 are intended to be included in § 50.34(f)(1)(i), the required plant/site specific probabilistic risk assessment. Item II.B.7 is covered by § 50.34(f)(2)(ix) and (3)(v). Items I.A.4.1 and I.C.1. are applied to operating plants and the substance is included in § 50.34(f)(2) (i) and (ii), respectively, for these CP/ML applications.

Another group of items is not applicable for various reasons. Item II.J.1.1 applies to NRC and not to CP/ML applicants. Item II.B.4, pertaining to crew training, is more appropriate as an OL item. Finally, II.E.2.1 requires the assessment of ECCS data by operating plant licensees and is not applicable to CP/ML applicants.

In summary, the Commission has reviewed and considered all of the additional requirements suggested by MPCA and has determined that they are either covered by provisions of the proposed rule or are not applicable or appropriate for construction permit and manufacturing license applications.

12. Comments on Certain Rule Requirements

The following discussion responds to the comments received on the specific items of 10 CFR 50.34(f) listed below:

(1)(i)—Plant/Site Specific PRA Study

A. Two commentors (S&W, CEC) point out that the NRC has not yet defined the methodology to be used in the PRA study.

Discussion

The Commission notes that a PRA Procedures Guide was issued as a draft for discussion by an IEEE technical symposium in October 1981, and will be issued in proposed final form for consideration at an ANS conference in April 1982. It is expected that the Guide will be published soon after the ANS conference. Meanwhile, plans for a PRA study, and the actual conduct of the study, need not wait until the safety goal and degraded core cooling rulemakings are resolved. During a meeting with the CP/ML applicants on April 8, 1981, the NRC staff made available a PRA program outline which should serve as a guideline for CP/ML applications. The program outline addresses issues such as the scope of the PRA study, how the PRA study should be performed, what should be considered in setting up a schedule, and, most importantly, how the results of the risk study should be factored into the design, fabrication and eventual operation of the plant to improve the reliability of core and containment heat removal systems. It is reasonable to expect that an applicant can utilize the staff guidelines to develop its own program for performing a meaningful PRA study. Consequently, the Commission will retain this requirement.

B. Another commentor (GE) expressed the belief that "completion of the PRA studies and comparison to a reasonable safety goal will demonstrate that the Boiling Water Reactor includes design features which ensures that the public health and safety is protected. If, on the other hand, the results of the studies * * * show that further risk reduction is appropriate, plant modifications * * * should be considered".

Discussion

Based on the risk studies performed to date, accident sequences relating to core and containment heat removal systems contribute substantially to overall accident risk. To reduce such risk, alternate system designs for core and containment heat removal systems should be considered and PRA studies should be performed in comparison with the PRA study for the original design. The outcome of the comparison should be selection of a system design from among several design alternatives that incorporates significant improvements in the reliability of core and containment heat removal systems.

C. Two commentors (TVA, B&W) suggested that the improvements that may result from the risk assessment should be those that are significant with respect to public health and safety, not just generally significant and practical.

Discussion

The aim of the probabilistic risk assessment, as expressed in the requirement, is to seek such improvements in the reliability of core and containment heat removal systems as are practical and do not impact excessively on the plant. The Commission believes that such improvements in reliability would also be significant with respect to public health and safety. Accordingly, the Commission does not consider it necessary to change the language of the requirement.

(1)(ii)—Auxiliary Feedwater System Evaluation

Two commentors (CEC, TVA) argued that the existence of paragraph (1)(i) regarding performance of a probabilistic risk assessment (PRA) makes paragraph (1)(ii) superfluous, since a PRA study would include the analyses and reviews discussed in (1)(ii) and in paragraphs (1)(iii)–(xii).

Discussion

The Commission does not agree with this comment. It is not at all certain that the PRA would necessarily include all parts of the evaluation called for in paragraph (1)(ii). The result might be non-uniform and incomplete submittals by the applicants, with consequent time-consuming reiterations. It is, therefore, important that the three parts of the auxiliary feedwater system evaluation be specified. However, if an applicant's PRA does, in fact, include all parts of the evaluation called for in paragraph (1)(ii), then this requirement will be satisfied.

(1)(iii)—Coolant Pump Seal Damage Evaluation

One commentor (CEC) states that paragraph (1)(iii) is superfluous, given the requirement for a plant/site specific probabilistic risk assessment (PRA) as specified in paragraph (1)(i).

Discussion

The rule requires applicants to evaluate reactor coolant pump seal damage and consequential added loss-of-coolant, following a small-break LOCA with loss of offsite power. The PRA might consider this area only peripherally, if at all, since its thrust is in the improvement of the reliability of core and containment heat removal systems. Accordingly, no change has been made in paragraph (1)(iii). However, this requirement will be satisfied if an applicant's PRA includes the evaluation called for in paragraph (1)(iii).

(1)(iv)—SBLOCA Probability Due to a Stuck-Open PORV

One commentor (CEC) argued that the PRA analyses required by paragraph (1)(i) would also include the analysis discussed in (1)(iv) in terms of the probability of small LOCA events. The commentor said, "the criteria for judging whether or not an improvement is to be made should, however, not rest with LOCA probabilities but rather with overall risk contribution and ultimately with the comparison of plant risk to a uniform safety goal."

Discussion

The WASH-1400 analysis for a PWR indicated that SBLOCAs contribute significantly to core melt probability. Furthermore, the TMI experience and subsequent analysis have shown that the likelihood of a SBLOCA due to a stuck-open PORV is greater than that assumed in WASH-1400. The purpose of this requirement is to determine whether this probability contributes substantially to the SBLOCA probability from all causes. If it does, an evaluation should be performed to ensure that this probability will be reduced by incorporating an automatic PORV isolation system, which will give assurance that the public health and safety is protected in the event of a stuck-open PORV. The Commission will retain this requirement. However, the requirement will be met if an applicant's PRA includes the analysis called for in (1)(iv).

(1)(v through xii)—Additional Studies

A. One commentor (CEC) states that all topics discussed in these paragraphs "could readily be considered in the PRA discussed in paragraph (1)(i)". Further, the commentor states that "it appears that many of the studies and criteria have a basis only in NRC staff judgment". Lastly, the commentor states that these studies, which are additional to the PRA discussed in paragraph (1)(i), "should be required only for those cases where the basic systems and related questions involved are shown to have a significant contribution to risk—in order to prioritize the work to be done and to conserve industry and NRC resources."

Discussion

In response to the first comment regarding paragraphs (1)(v through xii), it is noted that the specific paragraphs requiring study or evaluation by the applicant resulted from recommendations by the Bulletins and Orders Task Force. This Task Force conducted generic reviews of loss-of-feedwater and small break loss-of-coolant events on operating PWRs designed by B&W, Westinghouse and Combustion Engineering, and on operating BWRs.

These items were not explicitly included in the PRA in (1)(i) to ensure that the areas are specifically addressed. In some cases, the generalized PRA may not be extended to cover the required area, for example: paragraph (1)(vi), study to identify practicable system modifications to reduce challenges to and failure of relief valves in BWRs. However, if an applicant's PRA does, in fact, include the items called for in paragraphs (1)(v through xvii), then these requirements will be satisfied.

With regard to the second comment, it is the judgement of the Commission that potentially significant increases in plant safety could evolve from these studies and evaluations. At this time, the Commission is awaiting results of these studies and evaluations to determine whether certain plant modifications are warranted to improve plant safety.

In response to the last question regarding paragraphs (1)(v through xii), the Commission considers a risk assessment one of many tools which may be used to evaluate plant modifications and improvements. Direct evaluation, as considered in these paragraphs, is an equally valid tool.

In view of the foregoing discussion, no changes have been made in paragraphs (1)(v through xii) as a result of this comment. However, the Commission has made changes in wording to clarify the intent of paragraphs (1)(vii), (viii) and (ix). Proposed paragraph (1)(xi) has been deleted since a generic study applicable to all the affected applicants has been submitted for Commission review.

B. Another commentor (GE) noted that the NRC staff has agreed that the requirements specified in II.K.3.24 of NUREG-0718 should apply only to loss of offsite alternating current power.

Discussion

The Commission concurs and has revised paragraph (1)(ix) as follows to clarify its intent:

Perform a study to determine the need for additional space cooling to ensure reliable long-term operation of the reactor core isolation cooling (RCIC) and high pressure coolant injection (HPCI)* systems, following a complete loss of offsite power to the plant for at least two (2) hours. (applicable to BWRs only) (II.K.3.24)

*For plants with high pressure core spray systems in lieu of high pressure coolant injection systems, substitute the words, "high pressure core spray" for "high pressure coolant injection" and "HPCS" for "HPCI."

(2)(iii)—Control Room Design

One commentor (PSO) states that the text conflicts with the predicate given in § 50.34(e)(2) and suggests rewording (2)(iii) to read: "Provide a control room design that applies state-of-the-art human factor principles (I.D.1)." Two other commentors (SRW, CEC) suggested that the design be submitted for NRC "review" instead of "approval" since the latter has specific legal connotations in the engineering area. The suggestion was also made that "the rule should stipulate that the control room design consider state-of-the-art human factor principles, since direct application of all such principles may conflict with existing regulations."

Discussion

In response to the first comment, it should be noted that section (2) does not require a control room design prior to the granting of a CP, only sufficient information to ensure that an appropriate design will be submitted prior to fabrication or revision of panels and layouts. The Commission agrees with the other comments and has amended the text to read as follows:

Provide, for Commission review, a control room design that reflects state-of-the-art human factor principles prior to committing to fabrication or revision of fabricated control room panels and layouts. (I.D.1)

(2)(vi)—Reactor Coolant System Vents

The commentor (CEC) notes that it may be well to review this requirement carefully on a plant specific basis to determine if any core cooling benefit can be identified; for some plants, reactor coolant system vents may offer no real benefit.

Discussion

The reactor coolant system high point vent requirement was developed to provide a means to eliminate gases that could inhibit core cooling. Since all plants have a potential to release non-condensible gases, this requirement applies to all plants. Although events in which gas venting would be required are highly unlikely, there does not appear to be an acceptable substitute at this time for those cases where venting may be needed. Consequently, the Commission is retaining this requirement, but has made a minor wording change for clarification. The paragraph now reads:

Provide the capability of high point venting of noncondensible * * *

(2)(vii)—Radiation and Shielding Design

One commentor (PSO) suggested inserting the words "Provide a plan and submit a schedule to" at the beginning of the text to clarify its intent.

Discussion

The Commission does not believe this change is necessary since the language under (f)(2) clearly indicates that only sufficient information is required prior to granting a CP to demonstrate that the requirements, e.g., (2)(vii), will be met by the operating license stage. However, the Commission has substituted the word "materials" for "fluids" in the text since not only fluids are involved, and the words "TID 14844 source term" have been substituted for "highly" for clarification.

(2)(ix)—Hydrogen Control System

A. One commentor (OPS) requests clarification of the word "handling" in the requirement, "Provide a system for hydrogen control capable of handling hydrogen generated by the equivalent of a 100% fuel-clad metal water reaction."

Discussion

The Commission has substituted the words "that can safely accommodate" for "capable of handling" to clarify the intent.

B. Several commentors (OPS, Bechtel, GE, W, CEC, TVA) asserted that the 100% metal/water reaction requirement is too stringent and inconsistent with the value of 75% metal/water reaction in the proposed interim rule on hydrogen.

Discussion

While it is true that the TMI-2 accident produced less hydrogen than that assumed in the rule, and that the 100% requirement is greater than the 75% requirement in the proposed interim rule, the Commission finds that 100% is appropriate as a conservative bound for the design of plants not yet under construction. More specifically, the amount of hydrogen should not be tied to a given accident sequence (e.g., TMI-2), but rather a class of accidents which produce a large amount of hydrogen but hold promise of being recoverable, that is, for cooling to be re-established prior to what would otherwise be a substantial core melt-down. The proposed interim rule will be limited to accidents for which no or limited core melting takes place. The CP/ML rule considers potential accidents that are more severe than those considered in the interim rule. These severe accidents will be the subject of the degraded core rulemaking.

C. Another commentor (B&W) suggested that a maximum rate of hydrogen generation should be provided for the hydrogen control system.

Discussion

The hydrogen generation rates and release rates into the containment are a function of the reactor type, the accident sequence being considered, and the recovery (of cooling) schemes employed. Further, the effects of hydrogen generation rates and release rates (in terms of burning or detonation) are dependent on blowdown and steam-inerting characteristics in the containment. Thus, one maximum rate would be inappropriate and possibly overly conservative. Not having a maximum rate does not necessarily mean that the Commission expects detailed mechanistic analyses of hydrogen generation and release for a variety of sequences. Parametric analysis that adequately scopes the physical processes for the sequences under consideration would be acceptable.

(2)(x)—Relief and Safety Valves

Two commentors (Bechtel, B&W) pointed out that this requirement appears to elevate ATWS to the status of a design basis event.

Discussion

This is not intended, as the Commission is presently reviewing a proposed ATWS rule. Appropriate valve qualification requirements for ATWS can only be finalized after the Commission issues a final ATWS rule or decides that plants do not have to be designed to withstand an ATWS event. To clarify the intent of this requirement, it has been revised to read as follows:

Provide a test program and associated model development and conduct tests to qualify reactor coolant system relief and safety valves and, for PWR's, PORV block valves for all fluid conditions expected under operating conditions, transients and accidents. Consideration of anticipated transients without scram (ATWS) conditions shall be included in the test program. Actual testing under ATWS conditions need not be carried out until subsequent phases of the test program are developed.

(2)(xii)—Auxiliary Feedwater System

A commentor (CE) suggests that the requirement to "provide an analysis of the effect on containment integrity and return to reactor power of automatic AFW system initiation with a postulated main steam line leak inside containment" be deleted since it would institute a regulatory requirement for an analysis of a condition normally assessed during the design of a safety-grade system, e.g., the auxiliary feedwater system. The commentor maintains that it is unnecessary to require this specific analysis in the rule.

Discussion

The Commission agrees with the comment and has deleted this part of the requirement because the regulations already require analyses of such systems (10 CFR 50.34(a)(4)). In addition, the term "safety-grade" has been deleted because that term is not explicitly defined in the regulations. With these changes, (2)(xii) now reads as follows:

Provide automatic and manual auxiliary feedwater (AFW) system initiation, and provide auxiliary feedwater system flow indication in the control room. (Applicable to PWRs only) (II.E.1.2.)

(2)(xvii)—Primary System Sensitivity to Transients

A commentor (Gilbert), referring to this requirement, said "some statements of design criteria are so general as to be nebulous". Another commentor (B&W) objected to "sensitivity" and "reduce" in this requirement as not well-defined terms, making it difficult to know what features must be provided. A third commentor (PGE) indicated that the reference to NUREG-0718 action plan item II.E.5.2 appears incorrect.

Discussion

The requirements in 10 CFR 50.34(f) are intended to be general enough to allow a reasonable amount of flexibility in their interpretation. However, the Commission has deleted this requirement because it has not yet been sufficiently defined. After further study, appropriate action on this subject will be implemented.

(2)(xix)—Indication of Inadequate Core Cooling

A commentor (PGE) suggested the use of "and/or" instead of "and" in the last sentence since the present wording implies that all of the instruments must be provided. Another commentor (B&W) suggested deleting the examples of instrumentation that may be required.

Discussion

The commentor's reference to the "last sentence" is not clear since (2)(xix) has only one sentence. The Commission believes that the words "such as" clearly indicates that what follows are examples of instrumentation that may be required. However, the words "exit" and "core coolant flow rate" have been eliminated to better reflect the design requirements. As revised and renumbered (2)(xviii), the paragraph now reads as follows:

Provide instruments that provide in the control room an unambiguous indication of inadequate core cooling, such as primary coolant saturation meters in PWR's, and a suitable combination of signals from indicators of coolant level in the reactor vessel and in-core thermocouples in PWR's and BWR's. [II.F.2]

(2)(xxi)—Power Supplies

A commentor (PGE) noted "the requirement that motive and control components be designed to safety grade criteria is inconsistent with the applicable requirement of NUREG–0737 (which is referenced in NUREG–0718)."

Discussion

Paragraph (2)(xxi) has been renumbered (2)(xx) and part (B) has been revised to read:

Motive and control power connections to the emergency power sources are through devices qualified in accordance with requirements applicable to systems important to safety.

(2)(xxii)—Auxiliary Heat Removal Systems

A commentor (PGE) noted that the reference to NUREG–0718 action plan item II.K.1.2 is incorrect.

Discussion

This reference has been corrected to II.K.1.22, and the paragraph has been renumbered (2)(xxi).

(2)(xxiv)—Anticipatory Reactor Trip

One commentor (B&W) indicates that a hard-wired, safety-grade reactor trip on loss of feedwater will be incorporated into the design of B&W plants; however, "B&W believes that the reactor trip upon turbine trip is disadvantageous." B&W states that "plants utilizing a once-through steam generator have the capability to run back on turbine trip without a reactor trip" and the "avoiding of a reactor trip for this event results in smaller perturbations in the primary system."

Discussion

Prior to the accident at TMI–2, B&W operating plants utilized a runback feature to avoid a reactor trip upon turbine trip. However, for each of these events, the PORV was opened to relieve reactor coolant system pressure. As part of the post–TMI–2 fixes to minimize challenges to the PORV, B&W designed plants were required to lower the high pressure reactor trip setpoint from 2355 psig to 2300 psig and raise the PORV setpoint from 2255 psig to 2450 psig. These actions removed the runback capability for turbine trip events. In addition, B&W plants were required to install anticipatory reactor trips for loss of feedwater and turbine trip.

On applications currently undergoing OL review, such as Midland, the applicant has proposed certain design modifications that may reduce the probability of a small break loss-of-coolant accident (SBLOCA) caused by a stuck-open PORV.

These modifications include:

(1) A fully qualified safety-grade PORV;

(2) Safety-grade indication of PORV position;

(3) Dual safety-grade PORV block valves, capable of being automatically closed if a PORV malfunction occurs;

(4) A test program to demonstrate PORV operability;

(5) Installation of a safety-grade reactor trip on total loss of feedwater; and

(6) Resetting the PORV and high pressure reactor trip setpoints to their original values of 2255 psig and 2355 psig, respectively.

Should these modifications be found acceptable by the staff, the necessity of installing an anticipatory reactor trip upon turbine trip may be negated. However, until these or similar modifications are proposed and found acceptable by the Commission, the plant design must incorporate anticipatory reactor trips for both loss of feedwater and turbine trip.

No change has been made in paragraph (2) (xxiv) because of the comments. However, the Commission has modified the wording for clarification and deleted the words "safety grade" because this term has not been defined in the regulations. The paragraph has been renumbered (2)(xxiii) and modified to read as follows:

Provide, as part of the reactor protection system, an anticipatory reactor trip that would be acutated on loss of main feedwater and on turbine trip. (Applicable to B&W-designed plants only) [II.K.2.10]

(2)(xxvi)—Recording Reactor Vessel Water Level

One commentor (GE) stated that this requirement should be deleted because task II.K.3.23 was not included in NUREG–0737.

Discussion

The TMI action plan, Table C.3, NUREG–0660, indicates that this issue is being covered in connection with TMI action plan item I.D.2, plant safety parameter display console; this latter item is identified in NUREG–0737. Specific console requirements for operating reactor licensees and OL applicants are under consideration by the Commission at the present time. The Commission considers that central water level recording is necessary for BWRs, and that it is appropriate to address such capability in a preliminary manner during the CP safety review. Consequently, this requirement will be maintained. However, the Commission has noted that the range over which the reactor vessel water level must be recorded as specified in the proposed rule is inconsistent with that specified in Regulatory Guide 1.97. Since either range is acceptable for the plants covered by the rule, the Commission has modified the requirement to allow that flexibility in its implementation. This paragraph has been renumbered (2)(xxiv) and changed to read as follows:

Provide the capability to record reactor vessel water level in one location on recorders that meet normal post-accident recording requirements. (Applicable to BWR's only) [II.K.3.23]

(2)(xxviii)—ALARA Exposures

A commentor (Bechtel) noted that this requirement applies to the design basis of systems outside containment likely to contain radioactive material, rather than the development of leakage control and detection provisions intended by NUREG–0718, Item III.D.1.1.

Discussion

The Commission has renumbered the paragraph (2)(xxvi) and, for clarification, replaced the requirement with the following.

Provide for leakage control and detection in the design of systems outside containment that contain (or might contain) TID 14844 source term radioactive materials following an accident. Applicants shall submit a leakage control program including an initial test program, a schedule for re-testing these systems, and the actions to be taken for minimizing leakage from such systems. The goal is to minimize potential exposures to workers and public, and to provide reasonable assurance that excessive leakage will not prevent the use of systems needed in an emergency. [III.D.1.1]

(3)(i), (ii), (iii)—Administrative Procedures and Quality Assurance

A. A commentor (Gilbert) stated that these requirements are a restatement of present 10 CFR requirements.

Discussion

Item (3)(i) has not been a previous requirement for CP reviews (recently, this has been identified as a requirement for OLs as item I.C.5, NUREG-0737) nor have Items (3) (ii) and (iii), as stated in the proposed rule, been previous CP requirements.

B. Three commentors (S&W, NQA, TVA) noted that the inference of section (3)(iii) is that Appendix B of 10 CFR 50 is not sufficiently definitive. If this is the case, the proper place to provide such clarification or additional requirements is through Appendix B. It is the recommendation of the NQA Committee that paragraphs 50.34(f)(3) (ii) and (iii) be deleted from the proposed addition to the regulations because they do not clarify Appendix B and can only add confusion.

Discussion

10 CFR Part 50 Appendix B does set forth basic QA criteria from which to develop a QA program. 10 CFR 50.34(a)(7) requires that the applicant describe its QA program in the PSAR and include a discussion of how the applicable requirements of Appendix B will be satisfied. Regulatory Guide 1.70 and the Standard Review Plan provide additional guidance on the extent to which this QA program should be described. The controls described in § 50.34(f)(3)(ii) and (iii) provide additional detailed criteria for proper implementation of Appendix B requirements.

C. Two commentors (NQA, Bechtel) noted that existing regulations contain provisions for the independence (separation) of those individuals who perform functions of attaining quality objectives from those individuals who verify compliance with requirements. Regulatory Guide 1.64 contains additional explanation for the intended independence for design verification purposes. The proposed addition to 10 CFR Part 50 goes beyond other regulations and regulatory guides and suggests the emphasis be placed on organizational independence rather than independence of personnel for objectivity and proficiency.

Discussion

The Commission agrees that Regulatory Guide 1.64 contains sufficient guidelines for independent verification of designs. Of particular concern to the Commission is the lack of sufficient independence of the organization responsible for performing checks, verifications, and inspections. Therefore, this aspect of an effective QA program is emphasized in the rule.

D. A commentor (NQA) also noted that (3)(iii)(B) "would require the entire body of quality assuring activities to be performed at the construction site. This would require massive upheaval and relocation to the construction site of not only top management, but also all support organizations."

Discussion

The objective of item B is to ensure that sufficient quality assurance and quality control activities are performed at the site rather than at corporate offices to provide closer management oversight and communication. To clarify the Commission's intent, (3)(iii)(B) has been modified to read:

(B) performing quality assurance/quality control functions at construction sites to the maximum feasible extent;

E. The commentors (NQA, Bechtel) noted that (3)(iii)(C) is not clear whether quality assurance personnel should be involved in development of the procedures or should be assigned actions through the procedures.

Discussion

The Commission agrees that this item needs clarification to ensure a better understanding of the intent. Item (3)(iii)(C) has been modified to read as follows: "including QA personnel in the documented review of and concurrence in quality-related procedures associated with design, construction, and installation."

F. A commentor (NQA) noted that (3)(iii)(D) is "not clear in what is meant by QA requirements. If this refers to the requirements for quality assurance programmatic activities, the statement is acceptable; if it refers to requirements for the physical characteristics for classes of equipment, the statement is inappropriate."

Discussion

The Commission agrees that this requirement should be clarified. (3)(iii)(D) has been revised to read: "establishing criteria for determining QA programmatic requirements;"

G. A commentor (NQA) noted that "existing regulations now require the establishing of qualification requirements for personnel performing quality assurance activities. Regulatory Guides such as 1.58 and 1.146 add additional clarification concerning personnel who perform quality verification activities. It is not at all clear what additional requirements are intended" by Section (3)(iii)(E).

Discussion

The Commission acknowledges that the existing regulations do require, although not explicitly, the establishment of such qualification requirements. However, the Commission is retaining the requirements stated in (3)(iii)(E) to ensure that they are considered in the QA program. The word "minimum" has been deleted from this section to be consistent with Appendix B to 10 CFR Part 50.

H. The commentor (NQA) notes "that existing regulations would require staffing the quality assurance unit of the organization commensurate with its duties and responsibilities. It is not at all clear how the organization is staffed commensurate with its 'importance to safety'. Ordinarily, duties and responsibilities reflect the importance of the activity to be performed." Part (3)(iii)(F) "is not clear what is intended by the addition of 'importance to safety'."

Discussion

To clarify the intent, (3)(iii)(F) has been modified by deleting the phrase "importance to safety". Existing regulations do not specifically address the numbers of QA/QC individuals required for the design and construction activities associated with building a nuclear power plant. The size of the QA/QC organization should be dependent upon the quantity and type of quality-related activities that are on-going or projected during the design and construction of the nuclear facility.

I. The commentor (NQA) notes, relative to (3)(iii)(G), "that existing regulations contain requirements for preparation and maintenance of documentation including 'as-built' documentation. The problem concerning procedures may lie not in the requirements for them or their establishment, but in their implementation; i.e., procedures are available, but they may not be being followed."

Discussion

Existing regulations (i.e., Criterion VI, "Document Control" of Appendix B to 10 CFR Part 50) establish QA requirements for "* * * instructions, procedures, and drawings * * *" but do not address "as-built" documentation (e.g., as-built drawings). Because the controls imposed upon as-built drawings, which accurately reflect the actual plant design, have been abused in the past, it is the Commission's position that as-built documentation be addressed specifically by the QA requirements contained in the design and construction QA program. Therefore, (3)(iii)(G) has not been modified.

J. Three commentors (S&W, NQA, Bechtel) assert that the intent of (3)(iii)(H) is not clear. The NQA said that "if intent is to place quality assurance personnel on the design and analysis team, their independence may be compromised. Appendix B now requires that during design, the activities of design control and design verification are to be identified, defined, performed in accordance with written procedures by persons having proper capabilities and sufficiently independent of those who produced the design, so as to eliminate any conflict of interest. This being true, it is not at all clear what is intended by the proposed addition."

Discussion

The Commission agrees that existing regulations (i.e., Criterion III, "Design Control" of Appendix B to 10 CFR Part 50) already establish the requirements that verification of the adequacy of design be "* * * performed by individuals or groups other than those who performed the original design * * *." However, it is the Commission's intent that design documents (e.g., drawings, specifications, etc.) also be reviewed by individuals knowledgeable and qualified in QA/QC techniques to ensure that the documents contain the necessary QA/QC requirements (e.g., inspection and test requirements). For this reason, (3)(iii)(H) has not been changed.

(3)(iv)—Containment Penetration

Several commentors (OPS, Gilbert, W. CEC, TVA) centered on the asserted arbitrariness of the requirement for a 3-foot diameter penetration, the lack of technical justification, and the possibility that containment venting provisions may not provide a significant contribution to safety.

Discussion

The containment penetration size was selected so that it would be consistent with mitigation features designed to accommodate medium- and slow-rate pressure rises in containments that would otherwise have failed. Among the features considered were filtered vented containment systems and passive containment cooling systems. Rapid-rate pressure rises from hydrogen burns, for example, were excluded from consideration. The 3-foot penetration was determined to be a conservative penetration size that would not preclude the eventual installation of one of the aforementioned features. Of course, there is the possibility that such penetrations will not be needed, but that will be known only after the completion of the degraded core rulemaking. Therefore, the Commission has retained this requirement so as not to preclude later installation of containment venting systems, if required.

(3)(v)—Containment Design

A. One commentor (OPS) interprets the information requested on post-inerting and ignition systems as not allowing pre-inerting as a hydrogen control measure. Another commentor (CE) states that the level of detailed criteria requested by the Commission for hydrogen control obviates the use of alternative approaches to hydrogen control which may be developed in the future, and recommends eliminating the detailed criteria.

Discussion

The Commission is not limiting the options for hydrogen control by including criteria for post-inerting and ignition systems. Other systems (e.g., pre-inerting) may be proposed to meet the requirements stated in the proposed rule. Also, the level of detail in the criteria does not restrict design options for the post-inerting and ignition systems. The information requested on these systems is needed to ensure that operation of these systems will not adversely impact the safe shutdown of the plant.

B. A commentor (OPS) suggested that, to be consistent with (2)(ix), "requirement (3)(v)(A) should be modified to permit containment analysis to be based on the performance characteristics of existing systems and/or systems to be added during final design." The commentor also suggested rewording (3)(v)(A) to make the text easier to read. In doing so, the commentor suggested deleting the explicit requirement that the containment withstand the added pressure resulting from post-accident operation of the inerting system and inserted "the internal pressure shall be the maximum calculated pressure or 45 psig, whichever is greater."

Discussion

Part (3)(v)(A), as written, does not preclude consideration of the performance characteristics of either existing systems or systems that may be added during the final design. Furthermore, the suggested phrase "maximum calculated pressure" makes the requirement somewhat ambiguous. The Commission believes the present wording expresses the requirements clearly; therefore, no change has been made.

C. One commentor (TVA) maintains that the ten-percent uniformly distributed hydrogen concentration limit in (3)(v)(B) is unrealistically restrictive and should be resolved as part of the degraded-core rulemaking.

Discussion

The Commission believes that the ten-percent limit is appropriate as a conservative bound for the design of plants under construction. Accordingly, this requirement remains unchanged.

D. One commentor (GE) contends that the requirement (3)(v)(D) that the containment structure accommodate inadvertent full inerting is unnecessarily conservative. The commentor argues that a post-accident inerting system may be designed such that inadvertent inerting during plant operation could entail actuation of only part of the overall system, resulting in lower containment pressures. Hence, it was requested that the rule only address the maximum possible inadvertent inerting for the given system design. The commentor also requested relief on the containment test pressure criterion required for plants utilizing a post-inerting system based on the argument that full inadvertent inerting could be prevented.

Discussion

It is the Commission's position that human error needs to be considered in the inadvertent actuation of the post-inerting system and that partial inadvertent inerting cannot be assured in this case. Therefore, accommodation of inadvertent full inerting will be required. However, (3)(v)(D) has been renumbered (3)(v)(B) and revised such that all containment designs affected by this rule must have the capability to safely accommodate the pressure resulting from inadvertent actuation from a post-accident inerting system. This requirement will ensure that post-accident inerting remains a viable option until an applicant's comparative evaluation (See (1)(xii)) is completed and final selection of the hydrogen control system is made.

E. One commentor (OPS) proposed wording changes in (3)(v)(E) to make the text easier to read. Another commentor (Bechtel) suggested other changes "to avoid applying environmental qualification requirements to safety related systems and equipment which would not be needed to accommodate the conditions occurring following significant core degradation." Bechtel also proposed "to allow demonstration of qualification of these items by analysis and judgment and not mandate that these conditions be specified as design bases for the equipment."

Discussion

Equipment required for safe shutdown must perform its safety function in the environment to which it will be exposed during normal, abnormal and accident conditions. If particular equipment is not needed during or after a hydrogen burn, it need not perform its function in that environment, provided it can be shown that the failure of the equipment will not adversely affect any other needed safety function or mislead the operator. In general, the acceptable methods of demonstrating equipment performance are by testing or analysis based on partial test data. Such demonstration based on analysis or judgment alone may not be acceptable in all cases. No change has been made in (3)(v)(E) because of the comments; however, the words "and maintaining containment integrity" have been inserted to clarify that this consideration is meant to be included, and the requirement has been expanded to be applicable to all containment designs, irrespective of the selected method of hydrogen control.

Additional Changes in Requirements

As a result of its consideration of the comments from the public, the Commission has deleted paragraph (2)(xvii) and changed the wording of several paragraphs of the proposed rule, as discussed above.

In addition, the Commission has modified the wording of several more paragraphs, as shown in the final rule, to clarify their intent, and has deleted paragraphs (1)(xi) and (2)(xxv) of the proposed rule for the reasons discussed below:

1. The requirement proposed in paragraph (1)(xi) is no longer needed since a generic study applicable to all of the affected applicants has been submitted for NRC staff review to demonstrate that the BWR core remains covered for anticipated transients combined with the worst single failure.

2. The requirement in paragraph (2)(xxv) concerning the type of pressure-operated relief valve is too specific and the purpose of the requirement is adequately covered in paragraph (2)(x).

Deletion of the three paragraphs cited above has resulted in appropriate renumbering of the succeeding paragraphs in the final rule.

Finally, the Commission has added a requirement (paragraph (1)(xii)) for a comparative evaluation of alternative hydrogen control systems and a requirement (paragraph (3)(v)(B)) that all containment designs must have the structural capability to safely accommodate the pressure resulting from inadvertent actuation of a post-accident inerting system. These new requirements ensure that the post-accident inerting method of hydrogen control remains a viable option until final selection of the method for hydrogen control is made.

Substance of the Rule

This rule, which has been drawn from NUREG-0718, Licensing Requirements for Pending Applications for Construction Permits and Manufacturing License, March 1981, imposes new safety requirements on pending construction permit and manufacturing license applications. The Commission has determined that these requirements must be met by all applicants for construction permits or manufacturing licenses whose applications are pending as of the effective date of the rule. Specifically, these applicants are: Duke Power Company (Perkins Nuclear Station, Units 1, 2 and 3), Houston Lighting & Power Company (Allens Creek Nuclear Generating Station, Unit 1), Portland General Electric Company (Pebble Springs Nuclear Plant, Units 1 and 2), Public Service Company of Oklahoma (Black Fox Station, Units 1 and 2), Puget Sound Power & Light Company (Skagit/Hanford Nuclear Power Project, Units 1 and 2), and Offshore Power Systems (License to Manufacture Floating Nuclear Plants). It should be noted, however, that there are some elements in the TMI Action Plan (NUREG-0660), not included in NUREG-0718, that have not yet been acted upon by the Commission. These are items that the Commission has directed be subject to further study before taking approval action. It is possible, therefore, that some of these items will be approved for implementation prior to completion of the licensing review of the pending construction permits or manufacturing license. In that event, such items might be added to this rule. The Commission is aware, however, that the applications covered by this rule have already been substantially delayed and the facility designs may be further advanced than normally expected at the construction permit and manufacturing license review stage. The Commission will take this into account as further requirements are considered. Full opportunity for public comment will be provided if additional requirements are contemplated which would apply to these applications.

While this rule contains the basic requirements set out in NUREG-0718, it does not incorporate the entirety of the document. In particular, the rule does not contain the detailed criteria contained in Appendix B to NUREG-0718 for satisfying many of the requirements. To have included such detail would have resulted in a rule that would be excessively detailed and restrictive.

In addition, this rule does not identify, as does NUREG-0718, the items from the TMI-2 Action Plan, NUREG-0660, that are considered either not applicable to pending construction permit and manufacturing license applications, or to be requirements of the type customarily left for the operating license stage. However, the Commission has reviewed NUREG-0718, as revised* to account for the changes made between the proposed and final rule, and has concluded that the list of TMI-related requirements contained therein can provide a basis for responding to the TMI-2 accident. Applicants may, of course, propose to satisfy the rule's requirements by a method other than that detailed in NUREG-0718, but in such cases must provide a basis for determining that the requirements of the rule have been met.

Based upon its extensive review and consideration of the issues arising as a result of the Three Mile Island accident, the Commission has decided that pending applications for a construction permit or manufacture license should be measured by the NRC staff and Presiding Officers in adjudicatory proceedings against the existing regulations, as augmented by this rule. It is the Commission's view that this new rule, together with the existing regulations, forms a set of regulations, conformance with which meets the requirements of the Commission for issuance of a construction permit or manufacturing license, with one exception. For the manufacturing license application, the hydrogen control provisions of the existing regulations, namely, 10 CFR 50.44 and Criterion 50 of Appendix A to 10 CFR Part 50, together with the hydrogen control provisions of the new rule (subsections (1)(xii), (2)(ix), and (3)(v), are to be considered necessary but not necessarily sufficient. That is, the issue of the sufficiency of the hydrogen control measures required by these provisions may be considered in the manufacturing license proceeding, and the Commission may decide to impose additional requirements. Further studies in the area of hydrogen control, containment loading, and mitigation may, at some later date, resolve this issue sufficiently so that it may be addressed by further rulemaking and removed from the pending manufacturing license proceedings.

Some of the proposed rule's provisions deal with studies to be conducted by the license applicants. The

*NUREG-0718, Revision 2, dated January 1982. NUREG documents may be purchased through the NRC/GPO sales program by writing to U.S. Nuclear Regulatory Commission, ATTN.: Sales Manager, Washington, D.C. 20555 or by calling (301) 4[illegible]30

Commission intends to impose license conditions upon all permits and licenses covered by this rule which will require submittal of these studies to the NRC for review and appropriate action. The license conditions will specify due dates or may require that studies be submitted prior to hardware procurement or other construction events.

Conforming Changes to 10 CFR Part 2. Several conforming changes have been made to 10 CFR 2.764. Because these amendments are non-substantive, notice-and-comment procedures are unnecessary. Although these amendments could be made immediately effective, they will be effective on the same date as the Part 50 amendments in this notice.

Views of Chairman Palladino and Commissioners Ahearne and Roberts. The Commission decision to establish a rule for pending construction permits and manufacturing licenses is based on the view that nuclear plants in the early stages of construction—where capital investment is relatively small—are most amenable to a generic regulatory approach. On the other hand, the Commission believes regulatory flexibility is needed for nuclear plants that are operating. This flexibility recognizes that operating plants—which represent a substantial capital investment—often need case-by-case review to determine the best way to make changes deemed necessary for public health and safety. Therefore, the Commission does not agree with Commissioner Bradford's views on this subject.

It is the Commission's view that this new rule, together with the existing regulations, is sufficient for issuance of a limited number of manufacturing licenses. As stated in the "Substance of the Rule" section above, however, the Commission may decide to impose additional requirements, and the sufficiency of the hydrogen control measures mandated by this rule and the existing regulations will remain a litigable issue in the manufacturing license proceeding pending further rule making based on the results of future studies. For the sake of clarity, it should be stated that for the construction permit proceedings covered by this rule, the existing regulations together with this new rule are both necessary and sufficient as regards hydrogen control measures. If the results of future studies warrant, the hydrogen control issue may, by further rulemaking, be removed from manufacturing license proceedings.

Additional Views of Chairman Palladino (with which Commissioner Bradford agrees). The CP/ML rule approved by the Commission does not require consideration of instability (buckling) for containment loading due to inadvertent inerting.

The staff recommended that the Commission include buckling in the CP/ML rule. It is the staff's opinion that prudent rule development would require that ASME code requirements for buckling be met for all high likelihood events that might affect the containment, such as inadvertent inerting. I agree with the staff's opinion on this requirement.

Separate Views of Commissioner Gilinsky. I approve this rule in its entirety as it applies to pressurized water reactors (PWR's) with standard large containments, which includes most such reactors. I also approve the rule as it applies to other reactors with the following exceptions:

I disapprove the hydrogen control provisions of the rule as they apply to General Electric Mark III plants and Westinghouse ice condenser plants, both of which have relatively smaller and weaker containments than standard PWR's, and are therefore less able to withstand possible post-accident hydrogen burns. Substantially stronger containments should have been required in both cases.

Under the rule, the Commission has permitted Mark III plants whose construction has not yet begun to protect against post-accident hydrogen burns by installing, among other means, essentially the same hydrogen control systems—electrical igniters intended to burn excess hydrogen in a controlled manner—that are being added to similar plants which are nearing completion.

The Commission has taken a more tentative approach in the case of PWR's with ice condenser containments. The rule provides that the hydrogen control requirements for these plants are to be "considered necessary but not necessarily sufficient," and that the sufficiency of these requirements may be litigated in the Manufacturing License proceeding. The Commission is apparently less sure about the efficacy of current hydrogen control systems in this case. The Commission states that further studies "may, at some later date, resolve this issue" so as to remove this issue from the proceeding by rulemaking.

The Commission does not have a technical basis for drawing a distinction in this instance between the unbuilt Mark III plants and the unbuilt ice condenser plants. Both types of plants have relatively weak containments, and stronger containments are needed in both cases. The Commission should have required such stronger containments now.

For the plants nearing completion, compromises had to be made to accommodate the realities of the plants' construction—in many cases the containment was already completed. No such compromises needed to have been made in the case of plants whose construction has not yet begun.

It is true that redesign of the containment and associated features would have been necessary and that this would have taken time. But we had the time. It is now almost three years since the Three Mile Island accident demonstrated that large hydrogen burns were possible and that such burns could generate pressures which exceed the capabilities of the smaller and weaker containments. It is unfortunate that the Commission did not face up to this issue earlier.

Separate Views of Commissioner Bradford. The Commission recently declined to consider a proposed rule (SECY-81-244) that would have imposed many of the lessons learned from the Three Mile Island accident on NRC licensees in regulation form. The arguments advanced against this approach were that such a regulation would reduce needed flexibility and would encompass too many different subjects within the scope of one rule. While both of those arguments were probably wrong in the context in which they were advanced, they apply precisely to the rule being promulgated here.[1] No legal or logical reason can be advanced that favors the imposition of this rule on the licensing process while weighing against the imposition of the similar rule on the operating reactors. The only possible governing principle is the convenience of the nuclear industry, which the Commission has

[1] In the context of the rejected rule for operating reactors, the Commission should have learned the real consequences of this kind of "flexibility" from its experience with fire protection. A similarly informal approach was attempted with the licensees following the 1975 Browns Ferry fire. As the very generous 1980 deadline approached, it was clear that many of the licensees had taken advantage of the absence of a firm rule to ignore actions that the NRC staff thought important. As a result, the Commission was finally forced to put its fire protection requirements in regulation form, meanwhile extending the deadlines out to a ludicrous seven or eight years for many plants.

With regard to the point that a single rule can encompass too many subjects, it is worth remarking that the danger is much less when the parties primarily affected by the rule are the licensees. They have the financial, legal, and technical resources to comment extensively on a complex rulemaking to such an extent that the Commission will be fully aware of the consequences of its rule before imposing it. Furthermore, the operating reactor rule provided for exemptions to be granted as necessary. The rule promulgated here contains no similar provision.

accommodated completely in both situations.

The Commission has already instructed the staff to use specific provisions in this rule as the basis for its position in contested construction permit cases. What it is now providing is that intervenors who wish to challenge the adequacy of some of the provisions proposed here will not be able to do so. In effect, the Boards are being required to rule against them without hearing their evidence.

This authoritarian obsession with the avoiding of public challenge has been a source of continuing trouble for nuclear power over the last decade. That it should now be applied to limit the lessons to be learned from the accident that it helped to cause provides an unsettling indication that the NRC may be returning to its former bad habits.

Additional Views of Commissioner Ahearne. Lest silence be taken as assent, I note that I strongly disagree with Commissioner Bradford's opinions of the reasons for declining to make SECY-81-244 into a rule, the reasons for making SECY-81-20D into a rule, the lessons learned from the fire protection rule, and of the NRC's approach to public hearings.

Further Additional Views of Commissioner Ahearne. The NRC staff "suggests that the Commission consider the desirability of further modifying section (3)(v)(B)(1) on page 81 to require that instability be considered in designing the containment to withstand inadvertent inerting." (P. 3, Secy 81-631, November 4, 1981)

The basis for this recommendation is a November 2, 1981 NRR memorandum "Containment Instability." (Enclosure 2 to Secy-81-631) In this memorandum, the reasons are given to be the following:

—the exemption for instability consideration under the inadvertent inerting condition may limit the usefulness of the rule by presenting the opportunity for technical challenges to future operation of plants choosing post accident inerting systems.

—ASME Code Service Limit A stress criteria are therefore required in the rule to assure with high confidence that inadvertent inerting occurring at any time in the life of a plant, or several times for that matter, would not result in degradation of the containment structure.

This staff suggestion was discussed at a meeting with the NRC staff, described in a December 17, 1981 memorandum by Dr. B. D. Liaw "NTCP/ML Rule Containment Structural Requirements." Dr. Liaw makes the following points:

—* * * the question centered around whether or not the *Code* buckling criteria needed to be considered for the inadvertent inerting conditions during normal operations.

—* * * the staff was asked whether or not there was a compelling technical reason to require that the code buckling criteria be considered. Or, to rephrase it, whether or not the containment shell of both ice condenser amd Mark III plants would buckle under the inadvertent inerting and test conditions.

—* * * The general consensus was that the containment would not buckle for the following reasons * * *

—* * * the Code has a factor of safety of 3 to 4 * * *

—* * * the Code limits are established for external pressure and uniaxial compression * * *

—* * * the case of discussion (here) is for internal pressurization that induces tension in most parts of the shell * * *

—* * * there was an agreement (by NRC staff management and technical personnel) that the question is really not a technical issue whether the containment shell would buckle under inadvertent inerting and test conditions.

As I wrote in my December 17th memorandum to my fellow Commissioners ("CP/ML Rule Containment Structural Requirements"):

I do not see the analytic case for requiring a buckling criterion * * * . I do not believe the Code buckling criterion is needed for inadvertent inerting. On the other hand, (t)his criterion also does not come close to meeting the detonation pressure (if there were a hydrogen explosion). If the Commission's position is that all containments should have an estimated pressure capability of X, we should address that issue directly.

I believe we must develop regulatory requirements based on reason. If we are substantially uncertain about an issue, we should leave it open to be debated in individual cases.

Regulatory Flexibility Statement. In accordance with the Regulatory Flexibility Act of 1980, 5 U.S.C. 605(b), the Commission hereby certifies that this rule will not have a significant impact on a substantial number of small entities. This rule affects five applicants for construction permits and one applicant for a manufacturing license. These applications are for permits or a license for plants that do not fall within the scope of the definition of "small entities" set forth in the Regulatory Flexibility Act in the Small Business Size Standards set out in regulations issued by the Small Business Administration at 13 CFR Part 121.

OMB Regulatory Requirements Clearance. The application requirements contained in this final rule affect fewer than 10 persons (applicants) and, therefore, are not subject to Office of Management and Budget clearance as required by Pub. L. 96-511.

Pursuant to the Atomic Energy Act of 1954, as amended, the Energy Reorganization Act of 1974, as amended, and Sections 552 and 553 of Title 5 of the United States Code, the following amendments to Parts 2 and 50 of Title 10, Chapter I, Code of Federal Regulations are published as a document subject to codification.

PART 50—DOMESTIC LICENSING OF PRODUCTION AND UTILIZATION FACILITIES

1. The authority citation for Part 50 reads as follows:

Authority: Secs. 103, 104, 161, 182, 183, 189, 68 Stat. 936, 937, 948, 953, 954, 955, 956, as amended (42 U.S.C. 2133, 2134, 2201, 2232, 2233, 2239); secs. 201, 202, 206, 88 Stat. 1243, 1244, 1246 (42 U.S.C. 5841, 5842, 5846), unless otherwise noted. Section 50.78 also issued under sec. 122, 68 Stat. 939 (42 U.S.C. 2152). Sections 50.80–50.81 also issued under Sec. 184, 68 Stat. 954, as amended: (42 U.S.C. 2234). Sections 50.100–50.102 issued under sec. 186, 68 Stat. 955; (42 U.S.C. 2236). For the purposes of sec. 223, 68 Stat. 958, as amended; (42 U.S.C. 2273), § 50.54(i) issued under sec. 161i, 68 Stat. 949; (42 U.S.C. 2201(i)), §§ 50.70, 50.71 and 50.78 issued under sec. 161o, 68 Stat. 950, as amended; (42 U.S.C. 2201(o)) and the Laws referred to in Appendices.

2. A new paragraph (f) is added to § 50.34 to read as follows:

§ 50.34 Contents of applications; technical information.

* * * * *

(f) *Additional TMI-related requirements.* In addition to the requirements of paragraph (a) of this section, each applicant for a light-water-reactor construction permit or manufacturing license whose application was pending as of (insert effective date of amendment) shall meet the requirements in paragraphs (b) (1) through (3) of this section. This rule applies only to the pending applications by Duke Power Company (Perkins Nuclear Station Units 1, 2 and 3), Houston Lighting & Power Company (Allens Creek Nuclear Generating Station, Unit 1), Portland General Electric Company (Pebble Springs Nuclear Plant, Units 1 and 2), Public Service Company of Oklahoma (Black Fox Station, Units 1 and 2), Puget Sound Power & Light Company (Skagit/Hanford Nuclear Power Project, Units 1 and 2), and Offshore Power Systems (License to Manufacture Floating Nuclear Plants). The number of units that will be specified in the manufacturing license, if issued, will be that number whose start of manufacture, as defined in the license application, can practically begin within a ten-year period commencing on the date of issuance of the manufacturing license.

but in no event will that number be in excess of ten. The manufacturing license will require the plant design to be updated no later than five years after its approval. Paragraphs (b)(1)(xii), (2)(ix), and (3)(v) of this section, pertaining to hydrogen control measures, must be met by all applicants covered by this rule. However, the Commission may decide to impose additional requirements and the issue of whether compliance with these provisions, together with 10 CFR 50.44 and Criterion 50 of Appendix A to 10 CFR Part 50, is sufficient for issuance of the manufacturing license may be considered in the manufacturing license proceeding.

(1) To satisfy the following requirements, the application shall provide sufficient information to describe the nature of the studies, how they are to be conducted, estimated submittal dates, and a program to ensure that the results of such studies are factored into the final design of the facility. All studies shall be completed no later than two years following issuance of the construction permit or manufacturing license.[2]

(i) Perform a plant/site specific probabilistic risk assessment, the aim of which is to seek such improvements in the reliability of core and containment heat removal systems as are significant and practical and do not impact excessively on the plant. (II.B.8)

(ii) Perform an evaluation of the proposed auxiliary feedwater system (AFWS), to include (applicable to PWR's only) (II.E.1.1):

(A) A simplified AFWS reliability analysis using event-tree and fault-tree logic techniques.

(B) A design review of AFWS.

(C) An evaluation of AFWS flow design bases and criteria.

(iii) Perform an evaluation of the potential for and impact of reactor coolant pump seal damage following small-break LOCA with loss of offsite power. If damage cannot be precluded, provide an analysis of the limiting small-break loss-of-coolant accident with subsequent reactor coolant pump seal damage. (II.K.2.16 and II.K.3.25)

(iv) Perform an analysis of the probability of a small-break loss-of-coolant accident (LOCA) caused by a stuck-open power-operated relief valve (PORV). If this probability is a significant contributor to the probability of small-break LOCA's from all causes, provide a description and evaluation of the effect on small-break LOCA probability of an automatic PORV isolation system that would operate when the reactor coolant system pressure falls after the PORV has opened. (Applicable to PWR's only). (II.K.3.2)

(v) Perform an evaluation of the safety effectiveness of providing for separation of high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) system initiation levels so that the RCIC system initiates at a higher water level than the HPCI system, and of providing that both systems restart on low water level. (For plants with high pressure core spray systems in lieu of high pressure coolant injection systems, substitute the words, "high pressure core spray" for "high pressure coolant injection" and "HPCS" for "HPCI") (Applicable to BWR's only). (II.K.3.13)

(vi) Perform a study to identify practicable system modifications that would reduce challenges and failures of relief valves, without compromising the performance of the valves or other systems. (Applicable to BWR's only). (II.K.3.16)

(vii) Perform a feasibility and risk assessment study to determine the optimum automatic depressurization system (ADS) design modifications that would eliminate the need for manual activation to ensure adequate core cooling. (Applicable to BWR's only). (II.K.3.18)

(viii) Perform a study of the effect on all core-cooling modes under accident conditions of designing the core spray and low pressure coolant injection systems to ensure that the systems will automatically restart on loss of water level, after having been manually stopped, if an initiation signal is still present. (Applicable to BWR's only). (II.K.3.21)

(ix) Perform a study to determine the need for additional space cooling to ensure reliable long-term operation of the reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) systems, following a complete loss of offsite power to the plant for at least two (2) hours. (For plants with high pressure core spray systems in lieu of high pressure coolant injection systems, substitute the words, "high pressure core spray" for "high pressure coolant injection" and "HPCS" for "HPCI") (Applicable to BWR's only). (II.K.3.24)

(x) Perform a study to ensure that the Automatic Depressurization System, valves, accumulators, and associated equipment and instrumentation will be capable of performing their intended functions during and following an accident situation, taking no credit for non-safety related equipment or instrumentation, and accounting for normal expected air (or nitrogen) leakage through valves. (Applicable to BWR's only). (II.K.3.28)

(xi) Provide an evaluation of depressurization methods, other than by full actuation of the automatic depressurization system, that would reduce the possibility of exceeding vessel integrity limits during rapid cooldown. (Applicable to BWR's only) (II.K.3.45)

(xii) Perform an evaluation of alternative hydrogen control systems that would satisfy the requirements of paragraph (b)(2)(ix) of this section. As a minimum include consideration of a hydrogen ignition and post-accident inerting system. The evaluation shall include:

(A) A comparison of costs and benefits of the alternative systems considered.

(B) For the selected system, analyses and test data to verify compliance with the requirements of (b)(2)(ix) of this section.

(C) For the selected system, preliminary design descriptions of equipmment, function, and layout.

(2) To satisfy the following requirements, the application shall provide sufficient information to demonstrate that the required actions will be satisfactorily completed by the operating license stage. This information is of the type customarily required to satisfy 10 CFR 50.35(a)(2) or to address unresolved generic safety issues.

(i) Provide simulator capability that correctly models the control room and includes the capability to simulate small-break LOCA's. (Applicable to construction permit applicants only) (I.A.4.2.)

(ii) Establish a program, to begin during construction and follow into operation, for integrating and expanding current efforts to improve plant procedures. The scope of the program shall include emergency procedures, reliability analyses, human factors engineering, crisis management, operator training, and coordination with INPO and other industry efforts. (Applicable to construction permit applicants only) (I.C.9)

(iii) Provide, for Commission review, a control room design that reflects state-of-the-art human factor principles prior to committing to fabrication or revision of fabricated control room panels and layouts. (I.D.1)

(iv) Provide a plant safety parameter display console that will display to operators a minimum set of parameters defining the safety status of the plant, capable of displaying a full range of important plant parameters and data

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[2] Alphanumeric designations correspond to the related action plan items in NUREG 0718 and NUREG 0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident." They are provided herein for information only.

trends on demand, and capable of indicating when process limits are being approached or exceeded. (I.D.2)

(v) Provide for automatic indication of the bypassed and operable status of safety systems. (I.D.3)

(vi) Provide the capability of high point venting of noncondensible gases from the reactor coolant system, and other systems that may be required to maintain adequate core cooling. Systems to achieve this capability shall be capable of being operated from the control room and their operation shall not lead to an unacceptable increase in the probability of loss-of-coolant accident or an unacceptable challenge to containment integrity. (II.B.1)

(vii) Perform radiation and shielding design reviews of spaces around systems that may, as a result of an accident, contain TID 14844 source term radioactive materials, and design as necessary to permit adequate access to important areas and to protect safety equipment from the radiation environment. (II.B.2)

(viii) Provide a capability to promptly obtain and analyze samples from the reactor coolant system and containment that may contain TID 14844 source term radioactive materials without radiation exposures to any individual exceeding 5 rem to the whole-body or 75 rem to the extremities. Materials to be analyzed and quantified include certain radionuclides that are indicators of the degree of core damage (e.g., noble gases, iodines and cesiums, and non-volatile isotopes), hydrogen in the containment atmosphere, dissolved gases, chloride, and boron concentrations. (II.B.3)

(ix) Provide a system for hydrogen control that can safely accommodate hydrogen generated by the equivalent of a 100% fuel-clad metal water reaction. Preliminary design information on the tentatively preferred system option of those being evaluated in paragraph (f)(xii) of this section is sufficient at the construction permit stage. The hydrogen control system and associated systems shall provide, with reasonable assurance, that: (II.B.8)

(A) Uniformly distributed hydrogen concentrations in the containment do not exceed 10% during and following an accident that releases an equivalent amount of hydrogen as would be generated from a 100% fuel clad metal-water reaction, or that the post-accident atmosphere will not support hydrogen combustion.

(B) Combustible concentrations of hydrogen will not collect in areas where unintended combustion or detonation could cause loss of containment integrity or loss of appropriate mitigating features.

(C) Equipment necessary for achieving and maintaining safe shutdown of the plant and maintaining containment integrity will perform its safety function during and after being exposed to the environmental conditions attendant with the release of hydrogen generated by the equivalent of a 100% fuel-clad metal water reaction including the environmental conditions created by activation of the hydrogen control system.

(D) If the method chosen for hydrogen control is a post-accident inerting system, inadvertent actuation of the system can be safely accommodated during plant operation.

(x) Provide a test program and associated model development and conduct tests to qualify reactor coolant system relief and safety valves and, for PWR's, PORV block valves, for all fluid conditions expected under operating conditions, transients and accidents. Consideration of anticipated transients without scram (ATWS) conditions shall be included in the test program. Actual testing
not be carried out until subsequent phases of the test program are developed. (II.D.1)

(xi) Provide direct indication of relief and safety valve position (open or closed) in the control room. (II.D.3)

(xii) Provide automatic and manual auxiliary feedwater (AFW) system initiation, and provide auxiliary feedwater system flow indication in the control room. (Applicable to PWR's only) (II.E.1.2)

(xiii) Provide pressurizer heater power supply and associated motive and control power interfaces sufficient to establish and maintain natural circulation in hot standby conditions with only onsite power available. (Applicable to PWR's only) (II.E.3.1)

(xiv) Provide containment isolation systems that: (II.E.4.2)

(A) Ensure all non-essential systems are isolated automatically by the containment isolation system.

(B) For each non-essential penetration (except instrument lines) have two isolation barriers in series.

(C) Do not result in reopening of the containment isolation valves on resetting of the isolation signal.

(D) Utilize a containment set point pressure for initiating containment isolation as low as is compatible with normal operation.

(E) Include automatic closing on a high radiation signal for all systems that provide a path to the environs.

(xv) Provide a capability for containment purging/venting designed to minimize the purging time consistent with ALARA principles for occupational exposure. Provide and demonstrate high assurance that the purge system will reliably isolate under accident conditions. (II.E.4.4)

(xvi) Establish a design criterion for the allowable number of actuation cycles of the emergency core cooling system and reactor protection system consistent with the expected occurrence rates of severe overcooling events (considering both anticipated transients and accidents). (Applicable to B&W designs only). (II.F.5.1)

(xvii) Provide instrumentation to measure, record and readout in the control room: (A) containment pressure, (B) containment water level, (C) containment hydrogen concentration, (D) containment radiation intensity (high level), and (E) noble gas effluents at all potential, accident release points. Provide for continuous sampling of radioactive iodines and particulates in gaseous effluents from all potential accident release points, and for onsite capability to analyze and measure these samples. (II.F.1)

(xviii) Provide instruments that provide in the control room an unambiguous indication of inadequate core cooling, such as primary coolant saturation meters in PWR's, and a suitable combination of signals from indicators of coolant level in the reactor vessel and in-core thermocouples in PWR's and BWR's. (II.F.2)

(xix) Provide instrumentation adequate for monitoring plant conditions following an accident that includes core damage. (II.F.3)

(xx) Provide power supplies for pressurizer relief valves, block valves, and level indicators such that: (A) Level indicators are powered from vital buses; (B) motive and control power connections to the emergency power sources are through devices qualified in accordance with requirements applicable to systems important to safety and (C) electric power is provided from emergency power sources. (Applicable to PWR's only). (II.G.1)

(xxi) Design auxiliary heat removal systems such that necessary automatic and manual actions can be taken to ensure proper functioning when the main feedwater system is not operable. (Applicable to BWR's only). (II.K.1.22)

(xxii) Perform a failure modes and effects analysis of the integrated control system (ICS) to include consideration of failures and effects of input and output signals to the ICS. (Applicable to B&W-designed plants only). (II.K.2.9)

(xxiii) Provide, as part of the reactor protection system, an anticipatory reactor trip that would be actuated on loss of main feedwater and on turbine trip. (Applicable to B&W-designed plants only). (II.K.2.10)

(xxiv) Provide the capability to record reactor vessel water level in one location on recorders that meet normal post-accident recording requirements. (Applicable to BWR's only). (II.K.3.23)

(xxv) Provide an onsite Technical Support Center, an onsite Operational Support Center, and, for construction permit applications only, a nearsite Emergency Operations Facility. (III.A.1.2).

(xxvi) Provide for leakage control and detection in the design of systems outside containment that contain (or might contain) TID 14844 source term radioactive materials following an accident. Applicants shall submit a leakage control program, including an initial test program, a schedule for re-testing these systems, and the actions to be taken for minimizing leakage from such systems. The goal is to minimize potential exposures to workers and public, and to provide reasonable assurance that excessive leakage will not prevent the use of systems needed in an emergency. (III.D.1.1)

(xxvii) Provide for monitoring of inplant radiation and airborne radioactivity as appropriate for a broad range of routine and accident conditions. (III.D.3.3)

(xxviii) Evaluate potential pathways for radioactivity and radiation that may lead to control room habitability problems under accident conditions resulting in a TID 14844 source term release, and make necessary design provisions to preclude such problems. (III.D.3.4)

(3) To satisfy the following requirements, the application shall provide sufficient information to demonstrate that the requirement has been met. This information is of the type customarily required to satisfy paragraph (a)(1) of this section or to address the applicant's technical qualifications and management structure and competence.

(i) Provide administrative procedures for evaluating operating, design and construction experience and for ensuring that applicable important industry experiences will be provided in a timely manner to those designing and constructing the plant. (I.C.5)

(ii) Ensure that the quality assurance (QA) list required by Criterion II, App. B, 10 CFR Part 50 includes all structures, systems, and components important to safety. (I.F.1)

(iii) Establish a quality assurance (QA) program based on consideration of: (A) Ensuring independence of the organization performing checking functions from the organization responsible for performing the functions; (B) performing quality assurance/quality control functions at construction sites to the maximum feasible extent; (C) including QA personnel in the documented review of and concurrence in quality related procedures associated with design, construction and installation; (D) establishing criteria for determining QA programmatic requirements; (E) establishing qualification requirements for QA and QC personnel; (F) sizing the QA staff commensurate with its duties and responsibilities; (G) establishing procedures for maintenance of "as-built" documentation; and (H) providing a QA role in design and analysis activities. (I.F.2)

(iv) Provide one or more dedicated containment penetrations, equivalent in size to a single 3-foot diameter opening, in order not to preclude future installation of systems to prevent containment failure, such as a filtered vented containment system. (II.B.8)

(v) Provide preliminary design information at a level of detail consistent with that normally required at the construction permit stage of review sufficient to demonstrate that: (II.B.8)

(A)(*1*) Containment integrity will be maintained (i.e., for steel containments by meeting the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Division 1, Subsubarticle NE-3220, Service Level C Limits, except that evaluation of instability is not required, considering pressure and dead load alone. For concrete containments by meeting the requirements of the ASME Boiler Pressure Vessel Code, Section III, Division 2 Subsubarticle CC-3720, Factored Load Category, considering pressure and dead load alone) during an accident that releases hydrogen generated from 100% fuel clad metal-water reaction accompanied by either hydrogen burning or the added pressure from post-accident inerting assuming carbon dioxide is the inerting agent. As a minimum, the specific code requirements set forth above appropriate for each type of containment will be met for a combination of dead load and an internal pressure of 45 psig. Modest deviations from these criteria will be considered by the staff, if good cause is shown by an applicant. Systems necessary to ensure containment integrity shall also be demonstrated to perform their function under these conditions.

(*2*) Subarticle NE-3220, Division 1, and subarticle CC-3720, Division 2, of Section III of the July 1, 1980 ASME Boiler and Pressure Vessel Code, which are referenced in paragraph (f)(3)(v)(A)(*1*) and (f)(3)(v)(B)(*1*) of this section, were approved for incorporation by reference by the Director of the Office of the Federal Register. A notice of any changes made to the material incorporated by reference will be published in the **Federal Register.** Copies of the ASME Boiler and Pressure Vessel Code may be purchased from the American Society of Mechanical Engineers, United Engineering Center, 345 East 47th St., New York, NY 10017. It is also available for inspection at the Nuclear Regulatory Commission's Public Document Room, 1717 H St., NW., Washington, D.C.

(*1*) Containment structure loadings produced by an inadvertent full actuation of a post-accident inerting hydrogen control system (assuming carbon dioxide), but not including seismic or design basis accident loadings will not produce stresses in steel containments in excess of the limits set forth in the ASME Boiler and Pressure Vessel Code, Section III, Division 1, Subsubarticle NE-3220, Service Level A Limits, except that evaluation of instability is not required (for concrete containments the loadings specified above will not produce strains in the containment liner in excess of the limits set forth in the ASME Boiler and Pressure Vessel Code, Section III, Division 2, Subsubarticle CC-3720, Service Load Category, (*2*) The containment has the capability to safely withstand pressure tests at 1.10 and 1.15 times (for steel and concrete containments, respectively) the pressure calculated to result from carbon dioxide inerting.

(vi) For plant designs with external hydrogen recombiners, provide redundant dedicated containment penetrations so that, assuming a single failure, the recombiner systems can be connected to the containment atmosphere. (II.E.4.1)

(vii) Provide a description of the management plan for design and construction activities, to include: (A) the organizational and management structure singularly responsible for direction of design and construction of the proposed plant; (B) technical resources director by the applicant; (C) details of the interaction of design and construction within the applicant's organization and the manner by which the applicant will ensure close integration of the architect engineer and the nuclear steam supply vendor; (D) proposed procedures for handling the transition to operation; (E) the degree of top level management oversight and technical control to be exercised by the applicant during design and construction, including the preparation and implementation of procedures necessary to guide the effort. (II.J.3.1)

PART 2—RULES OF PRACTICE FOR DOMESTIC LICENSING PROCEEDINGS

3. The Authority citation for Part 2 reads as follows:

Authority: Secs. 161p and 181, Pub. L. 83–703, 68 Stat. 950 and 953, (42 U.S.C. 2201(p) and 2231; sec 191, as amended, Pub. L. 87–615, 76 Stat. 409 (42 U.S.C. 2241); sec 201, as amended, Pub. L. 93–438, 88 Stat. 1242 (42 U.S.C. 5841); 5 U.S.C. 552; unless otherwise noted. Sections 2.200–2.206 also issued under sec. 186, Pub. L. 83–703, 68 Stat. 955 (42 U.S.C. 2236) and sec. 206, Pub. L. 93–438, 88 Stat. 1246 (43 U.S.C. 5846). Sections 2.800–2.808 also issued under 5 U.S.C. 553.

4. Paragraphs (e)(1)(ii) and (e)(3)(iii) of § 2.764 are revised to read as follows:

§ 2.764 Immediate effectiveness of certain initial decisions.

* * * * *

(e) * * *

(1) * * *

(ii) In reaching their decisions the Boards should interpret existing regulations and regulatory policies with due consideration to the implications for those regulations and policies of the Three Mile Island accident. As provided in paragraph (e)(3) of this section, in addition to taking generic rulemaking actions, the Commission will be providing case-by-case guidance on changes in regulatory policies in conducting its reviews in adjudicatory proceedings. The Boards shall, in turn, apply these revised regulations and policies in cases then pending before them to the extent that they are applicable. The Commission expects the Licensing Boards to pay particular attention in their decisions to analyzing the evidence on those safety and environmental issues arising under applicable Commission regulations and policies which the Boards believe present serious, close questions and which the Boards believe may be crucial to whether a license should become effective before full appellate review is completed. Furthermore, the Boards should identify any apects of the case which in their judgment, present issues on which prompt Commission policy guidance is called for. The Boards may request the assistance of the parties in identifying such policy issues but, absent specific Commission directives, such policy issues shall not be the subject of discovery, examination, or cross-examination.

* * * * *

(3) * * *

(iii) In announcing the result of its review of any Appeal Board stay decision, the Commission may allow the proceeding to run its ordinary course or give whatever instructions as to the future handling of the proceeding it deems appropriate (for example, it may direct the Appeal Board to review the merits of particular issues in expedited fashion; furnish policy guidance with respect to particular issues; or decide to review the merits of particular issues itself, bypassing the Appeal Board).

Dated at Washington, D.C., this 12th day of January 1982.

For the Nuclear Regulatory Commission.

Samuel J. Chilk

Secretary of the Commission

[FR Doc. 82-1174 Filed 1-14-82; 8:45 am]

BILLING CODE 7590-01-M

SMALL BUSINESS ADMINISTRATION

13 CFR Part 101

[Rev. 2, Amdt. 22]

Administration; Delegations of Authority To Conduct Program Activities in Field Offices

AGENCY: Small Business Administration.

ACTION: Final rule.

SUMMARY: SBA is revising its delegations of authority to field offices. This revision will incorporate changes in the Agency's lending programs and organization of statutory provisions caused by the enactment of Pub. L. 97–35; reorganization of SBA's field office structure including the installation of the new Area Director (Disaster) and other disaster positions; and additionally cancels the Pilot Program in the Columbia, S.C. District Office.

EFFECTIVE DATE: January 15, 1982.

FOR FURTHER INFORMATION CONTACT: Ronald Allen, Paperwork Management Branch, Small Business Administration, 1441 "L" Street, NW., Washington, D.C. 20416 (202) 653–8538.

SUPPLEMENTARY INFORMATION: Part 101 consists of rules relating to the Agency's organization and procedures; therefore, notice of proposed rulemaking and public participation thereon as prescribed in 5 U.S.C. 553 is not required and this revision of Part 101 is adopted without resort to those procedures.

PART 101—ADMINISTRATION

Accordingly, pursuant to authority in Section 5(b)(6) of the Small Business Act, 15 U.S.C. 634, § 101.3–2 of Part 101, Chapter I, Title 13 of the Code of Federal Regulations is revised to read as follows:

§ 101.3-2 Delegations of authority to conduct program activities in field offices.

Pursuant to authority vested in me by the Small Business Act, 72 Stat. 384, as amended, and the Small Business Investment Act of 1958, 72 Stat. 689, as amended, the following authority is hereby delegated to field positions as hereinafter set forth:

Preface

The policies, rules, procedures and other requirements, as well as citations to the statutes, governing the programs for which this delegation of authority is issued, are contained in various parts of the Regulations of the Small Business Administration, Chapter I of Title 13 of the Code of Federal Regulations, as amended from time to time in the **Federal Register**.

Part I—Financing Program

Section A—Loan Approval Authority

1. Business Loans (Small Business Act) (SBAct).

a. To approve or decline direct and immediate participation section 7(a) business loans (except section 7(a)(13) loans) not exceeding the following amounts (SBA share):

	Approve	Decline
(1) Regional Administrator	$350,000	$350,000
(2) Deputy Regional Administrator	350,000	350,000
(3) Assistant Regional Administrator/F&I	350,000	350,000
(4) District Director	350,000	350,000
(5) Deputy District Director	350,000	350,000
(6) Assistant District Director/F&I	350,000	350,000
(7) Chief, Financing D/O	350,000	350,000
(8) Financial Management Assistance Officer-Minneapolis, MN D/O	350,000	350,000
(9) Supervisory Loan Specialist, Financing D/O	250,000	350,000
(10) Branch Manager, Buffalo, Elmira, Corpus Christi and El Paso	350,000	350,000
(11) Branch Manager, Except Fairbanks Buffalo, Corpus Christi, Elmira and El Paso	250,000	350,000
(12) Assistant Branch Manager/F&I, Biloxi, Milwaukee, and Springfield B/O's only	250,000	350,000
(13) Branch Manager, Fairbanks B/O only	150,000	150,000
(14) Assistant Branch Manager/F&I, Corpus Christi, and El Paso, B/O's only	350,000	350,000

b. Guaranty Loans. 7(a) business loans (except section 7(a)(13) loans):

	Approve	Decline
(1) Regional Administrator	$500,000	$500,000
(2) Deputy Regional Administrator	500,000	500,000
(3) Assistant Regional Administrator/F&I	500,000	500,000
(4) District Director	500,000	500,000
(5) Deputy District Director	500,000	500,000
(6) Assistant District Director/F&I	500,000	500,000
(7) Chief, Financing D/O	500,000	500,000
(8) Financial/Management Assistance Officer, Minneapolis, MN, D/O	500,000	500,000
(9) Supervisory Loan Specialist, Financing, D/O	250,000	500,000
(10) Branch Manager, Corpus Christi, El Paso, Milwaukee, and Springfield	500,000	500,000
(11) Branch Manager, Buffalo and Elmira	350,000	500,000