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BALTIMORE
GAS AND
ELECTRIC

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CHRISTIAN H. POINDEXTER
VICE CHAIRMAN OF THE BOARD
(301) 234-7803

June 7, 1991

K.B.
Brief me on results of this
JT

Mr. James M. Taylor
Executive Director for Operations
United States Nuclear Regulatory Commission
Washington, DC 20555

Dear Jim:

Enclosed are copies of a number of documents issued by the State of Maryland Public Service Commission. The most recent base rate case decision rendered by the Commission in the matter of Baltimore Gas and Electric Company's rates is dated December 17, 1990. The discussion of the activities which we brought up in the meeting with Commissioner Rogers on April 29 begins on page 60. An important fact to note is that the twelve month operating expenses for Calvert Cliffs for the period ended July 31, 1990, as defined in this case, were $142 million. In fact, I testified during the hearings that our projected O&M expenses for Calvert Cliffs for calendar year 1990 would be about $175 million, and we were expecting about $185 million for calendar year 1991. As is typically the case with the Maryland PSC, rates are set on a historical test period, so there's a considerable lag between the recovery of costs and actual expenditures. It is interesting to note that the period 1986 through 1988, we had the third lowest operating and maintenance expenses in the industry. Even with our significant increases recently, we are still below median for all of the nuclear power plants in the country.

On page 68 of the decision is a paragraph where the Maryland Public Service Commission states what they think their charge is relative to nuclear safety. It references a 1989 decision, an excerpt of which I have also enclosed.

Finally, I have attached a copy of our request for rehearing on the four nuclear issues that the PSC denied in this year's rate case. The Commission denied rehearing on the basis that an appeal had been filed in circuit court and the Commission no longer had jurisdiction.

I would be happy to come to Rockville for a more detailed discussion of any of these aspects of the State Economic Regulation if you would so desire.

Sincerely,

Chris Poindexter

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STATE OF MARYLAND
PUBLIC SERVICE COMMISSION

ORDER NO. 69054

IN THE MATTER OF THE APPLICATION OF BALTIMORE GAS AND ELECTRIC COMPANY FOR REVISIONS IN ITS ELECTRIC RATES.	* * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 8278

BEFORE:

Frank O. Heintz, Chairman

William A. Badger, Commissioner

Lilo K. Schifter, Commissioner

DATE ISSUED: December 17, 1990

STATE OF MARYLAND
PUBLIC SERVICE COMMISSION

TABLE OF CONTENTS

STATE OF MARYLAND
PUBLIC SERVICE COMMISSION

Appearances

Roger D. Redden, Harvey J. Reed, and David M. Perlman, for Baltimore Gas and Electric Company.

Robert H. McGowan and M. Catherine Dowling, for the Staff of the Public Service Commission.

John M. Glynn, Paul S. Buckley, Theresa V. Czarski, Paula M. Carmody, and Christopher R. Cook, for the Maryland Office of People's Counsel.

Robert R. Morrow, for General Motors Corporation.

Edward F. Shea, Jr. and Jeral A. Milton, for Bethlehem Steel Corporation.

Allan J. Malester and Charles R. Bacharach, for the Maryland Industrial Group.

John G. Short and Richard R. Butterworth, for the General Services Administration representing Federal Executive Agencies.

Timothy F. Umbreit and Shawn A. Matlock, for the Building Owners and Managers Association of Metropolitan Baltimore, Inc.

STATE OF MARYLAND
PUBLIC SERVICE COMMISSION

ORDER NO. 69054

IN THE MATTER OF THE APPLICATION OF BALTIMORE GAS AND ELECTRIC COMPANY FOR REVISIONS IN ITS ELECTRIC RATES.	* * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 8278

INTRODUCTION

On May 21, 1990, Baltimore Gas and Electric Company ("BG&E" or "Company") filed with the Commission an Application for authority to increase its base rates for electric service in two steps. The first step, totaling $198 million in annual base rate revenues, had a proposed effective date of June 20, 1990. The second step, totaling $52 million in annual base rate revenues, would be effective on and after June 1, 1991. The Application also indicated that on May 1, 1991, the Company would file a request to change its Electric Fuel Rate in order to reflect the anticipated fuel savings associated with bringing Unit 2 of the Brandon Shores Generating Station on line. The proposed step-two increase in base rates would be offset by a concomitant decrease in the Fuel Rate so that no change in BG&E's overall price of electricity would take place on June 1, 1991.

According to the Company's Application, the proposed rates are necessary to offset attrition, to reflect costs associated with the commercial operation of Brandon Shores Unit 2, and to recover purchased capacity charges.

By Order No. 68813, entered in this proceeding on May 25, 1990, the Commission suspended the rates filed by the Company for a period of 150 days from June 20, 1990, and instituted proceedings as to the justice and reasonableness thereof. By Order No. 69010, entered on November 5, 1990, the Commission extended the suspension period for an additional 30 days, the maximum period authorized by The Public Service Commission Law ("The PSC Law").[1]

During the course of the proceeding, the Company revised its rate request downward. The initial revision to $193.56 million, reflected actual operating results as of July 31, 1990. The second revision, to $191.895 million, was in response to certain evidentiary presentations during the hearings in this matter.

The Office of People's Counsel ("OPC") and the Commission's Staff ("Staff") entered their respective appearances, and permission to intervene was granted to: the Maryland Industrial Group ("MIG"), General Motors Corporation ("GM"), Bethlehem Steel Corporation ("Beth Steel"), the General Services Administration ("GSA") representing the Federal Executive Agencies, and the Building Owners and Managers Association of Metropolitan Baltimore ("BOMA").

Testifying on behalf of BG&E were Christian H. Poindexter, Vice Chairman of the Board; Edward A. Crook, President Utility Operations; Thomas F. Brady, Vice President,

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[1] Md. Ann. Code art. 78, Section 70(b) (1988 Repl. Vol.).

Accounting and Economics; George C. Creel, Vice President, Nuclear Energy; Richard M. Bange, Jr., Manager, Accounting Department; S. Edward Hargest, Manager Economic Research Department; Richard H. Vollmer, Vice President, TENERA L. P.; Gary R. Doughty and Stephen J. Marmaroff, both Vice Presidents of The Nielsen-Wurster Group, Inc.; and Dr. Charles E. Olson, President of Olson & Company, Inc.

The Commission Staff presented the testimony of David L. Valcarenghi, Lawrence W. Webster, and Shirley D. Davies of the Accounting Division; and Roger E. Larsen, Barry I. Levi, and Patricia Ferguson of the Rate Research and Economics Division.

The Office of People's Counsel proffered testimony by Kenneth F. Gallagher, Vice President of Commonwealth Consulting Group; Basil P. Kononetz and Urey Gene Hooper, Theodore Barry & Associates; John K. Stutz, Vice President of the Tellus Institute;, Paul L. Chernick, Vice President of Resource Insight, Inc.; and Basil L. Copeland, Jr., a principal in Chesapeake Regulatory Consultants, Inc.

Appearing on behalf of MIG were Stephen J. Barron and Randall J. Falkenberg, both Vice Presidents and Principals with Kennedy and Associates. Bethlehem Steel and General Motors co-sponsored the testimony of Nicholas Phillips, Jr. and James T. Selecky, both with Drazen-Brubaker & Associates, Inc. Testifying on behalf of GSA were Phillip R. Winter, Operations Research Analyst, Office of Procurement, GSA; and Thomas J.

Prisco, Staff Accountant and Financial Advisor, Department of the Army. Testifying for BOMA were David R. Frederick, Executive Vice President and Chief Operating Officer of W. C. Pinkard & Co., Inc.; Duke S. Kassolis, Vice President and Director Commercial and Retail Properties, Office and Community Development for The Rouse Company; Leonard H. Rosenberg, Jr., President of L. H. Rosenberg & Associates; and Thomas Shaner, President of The Joseph E. Shaner Company.

In addition to the evidentiary hearings conducted at the Commission's offices, four evening hearings were held at various locations in the Company's service territory for the purpose of receiving public comment. These hearings were duly advertised by means of a bill insert to customers' bills.

The ratepayers who spoke at the public hearings stated their opposition to the Company's rate request, voicing concerns about the magnitude of the proposed increase. Some expressed the opinion that the Company should achieve cost savings rather than request increased rates. Others criticized BG&E's management for the problems at the Calvert Cliffs Nuclear Power Plant. Still others felt that, in view of the rising cost of living and the developing recession, a rate increase would be harmful to the public interest.

In addition to the comments from those attending the public hearings, the Commission received written communications and numerous form letters from persons who were unable to attend the hearings but wanted to add "two cents" to the

debate. (Two pennies were attached to each letter as a "counter offer" to BG&E's rate request; the money will be forwarded to the Company's Fuel Fund for the needy.) The petitioners expressed concern that ratepayers should not be charged for BG&E's "mismanagement of resources" and that "to allow such a massive rate increase would be rewarding the utility's poor business practices."

The Commission has been mindful of the concerns expressed by the Company's customers in evaluating the rate request. We have based our decision as to the issues in this case on the evidence in the record, fully taking into account the position of the ratepayers, consistent with the statutory standards for establishing just and reasonable rates.

I. TEST YEAR

All of the parties to this proceeding have utilized, and we shall adopt, a test year comprised of the 12-month period ended July 31, 1990.

II. BRANDON SHORES UNIT 2

By the end of May 1991, it is expected that Brandon Shores Unit 2 ("BSU-2") a new, $662.0 million, 640 megawatt ("MW") coal-fired, base load plant will be operational.

Whenever a base load plant enters commercial operation, there is an immediate, substantial increase in revenue requirements to provide for recovery of capital, depreciation, and operation and maintenance expenses ("O&M"). The Commission must permit BG&E an opportunity to recover this increase through rates as long as BG&E shows that the costs are reasonable and the plant is necessary to serve needs of customers. Importantly, however, part of the incremental cost will be offset by savings in fuel costs, since the new coal-fired unit displaces more expensive generation and purchased power.

No party challenges the capital cost associated with the construction of BSU-2 or the need for the plant to accommodate new residential, commercial and industrial growth as well as increased energy consumption by existing customers. BG&E witness Crooke testified that BSU-2 will cost about $1,031 per kilowatt ("kW") of production capacity, which "compares very favorably" to $1,225 for a typical coal-fired unit of similar size. Mr. Crooke also discussed BG&E's strong load growth over the last five years and the Company's efforts to meet it, including the acceleration of BSU-2's in-service date from 1992 to 1991.

While BSU-2 was originally scheduled to be placed into commercial operation in 1978, BG&E has deferred the plant several times to more properly align the in-service date with forecasted load growth. While demands of customers have led to an acceleration of the in-service date by one year, the Company

witness testified that earlier deferrals, efforts to maintain flexibility and various cost controls have combined to minimize the BSU-2 revenue requirement.

The principal issue in this proceeding concerns the timing and method of recovering the increased revenue requirement associated with BSU-2 becoming used and useful. The parties propose various ways of reflecting BSU-2 in rates. The proposals run the gamut from the traditional to the novel.

BG&E sponsors a phase-in of the costs of BSU-2 to reflect concerns about gradualism that the Commission has enunciated in addressing the need to impose significant increases in customer rates. The phase-in would occur in three steps, and is structured so that customers' payments in 1991 for BSU-2 are the same as would be established under traditional rate-making.

According to BG&E witness Bange, the application of traditional rate-making principles would require a $124 million base rate increase in June 1991 for Brandon Shores alone. However, this increase would be offset partially by a decrease in the fuel rate as previously discussed. At this time, BG&E projects a savings in fuel costs of $52 million. Thus, even if the Commission excludes increases in other costs of BG&E's operations, a $72 million or 4.1 percent rate increase is necessary to cover the operating and capital costs of placing BSU-2 into commercial operation.

According to BG&E, the three-step phase-in of BSU-2 would be accomplished in the following manner:

(1) At the conclusion of this case, base rates would increase by $45 million, or 2.6 percent, through a recovery of capital costs associated with $333 million of BSU-2 investment.

(2) In June 1991, base rates would be increased by an additional $52 million, but would be offset entirely by a decrease in the fuel rate. This revenue requirement would recover capital costs on another $167 million of BSU-2 investment as well as estimated O&M and depreciation expenses. After the in-service date, BG&E would accrue AFUDC on that part of BSU-2 not receiving a cash return, and depreciation would be deferred with carrying charges.

(3) In January 1992, a $32 million increase would take effect, representing a 1.7 percent increase in base rates. At that time, BG&E would then earn a return on its entire investment, including recovery of the remaining annual operating expenses, as well as the deferred depreciation and AFUDC over a five-year period.

According to BG&E, the advantage of a phase-in is that it bridges a gap between rate cases, and gradually introduces the cost of BSU-2 into rates. In contrast, all other parties oppose the phase-in proposal. While the reasons vary from party to party, several common themes emerge in the testimony and argument.

First, some parties suggest that a phase-in violates the matching principle, by recognizing post-test year rate base changes and estimated expenses, but not additional revenues. Others say that a phase-in contravenes precedent, by allowing a return on Construction Work in Progress ("CWIP") before the in-service date, and without any showing of financial hardship. Still others note that BSU-2's cost and in-service date are not yet known and certain, and that Financial Accounting Standards Board ("FASB") Statement No. 92 may prevent the Commission from correcting the effect of any errors in estimation.

Contrary to BG&E's suggestion that a phase-in of the costs associated with BSU-2 is more advantageous to its customers, some parties state that a phase-in will be more expensive to ratepayers on a present value basis than traditional rate-making treatment. Moreover, many believe that the rate shock associated with the traditional ratemaking treatment of BSU-2 is not so significant as to warrant the extraordinary remedy of a phase-in since the accompanying fuel cost savings will result in only a four percent BSU-2 rate increase. Finally, the parties stress that there are many alternatives to a phase-in that recover BSU-2 costs in a timely manner, without endangering the interests of ratepayers.

As an alternative to the Company's proposed phase-in, GM/Beth Steel witness Selecky offered a deferred accounting method, which he says has been used by other states. Under this approach, the Commission would authorize BG&E to record a

deferred return on and of its BSU-2 investment beginning with the date of commercial operation. In the next rate case, the deferred amounts would be added to rate base and then amortized or depreciated over the life of the plant.

Like other proposals, the deferred accounting approach is appealing in certain ways. It considers all elements of the rate-making process. There is no matching problem. An historic test year is used. There is no need to adjust for O&M expense and rate design decisions are no more difficult than in any other base rate case.

GM also asserts that deferred accounting will obviate one step of a rate increase. This argument is based on the testimony of BG&E witness Brady. He said that, even if a surcharge or similar relief is granted, BG&E may file for another base rate increase in the middle of 1991. Thus, instead of three rate increases in a 12-month period, deferred accounting would provide for two, each in effect for a full calendar year. GM suggests that customers want fewer changes in rates.

Of course, there are problems with deferred accounting. Mr. Bange offered three objections. First, he testified that the revenue requirement for BSU-2 will be greater in January 1992 than under a traditional rate-making approach in June 1991. Next, he notes that BG&E cannot reflect the equity portion of the accrued carrying costs on BSU-2 in its financial

statements. Lastly, Mr. Bange objects to Mr. Selecky's failure to provide for the recovery of O&M expense, which will occur when BSU-2 is placed in service.

Another alternative to the Company's phase-in proposal is a surcharge for BSU-2 that would take effect when the unit is placed in service. In several past cases, the Commission has used a surcharge to reflect an increase in revenue requirements from generation or purchased power that occurs outside of both the test year and the statutory suspension period. *See* Re Delmarva Power & Light Company, 73 Md. PSC 810, 820-821 (1982) (authorization to file a surcharge for return to service of Edge Moor Unit 3 which was rolled into the tariffed base rate); Re Potomac Edison Company, 76 Md. PSC 451 (1985) (authorization to file a surcharge and revised fuel rate for purchase from Bath County project); and Re Baltimore Gas & Electric Company, 80 Md. PSC 496 (1989) (authorization to file a surcharge for capacity purchase from Pennsylvania Power & Light Company, conditioned on a showing of an inability to earn the authorized return).

Staff sponsors three surcharge proposals for our consideration in this proceeding. While the methods of computation vary, all three surcharges are contingent on BG&E earning less than its authorized return at the time of commercial operation, after adjusting for BSU-2. The Commission would determine the need for a surcharge by examining the quarterly

earnings report that BG&E will file on March 31, 1991. If a surcharge is necessary, Staff would reduce the fuel rate at the same time to reflect the estimated savings in fuel costs.

Under Staff's first method, a surcharge would be computed by dividing the total BSU-2 revenue requirements by actual test year billing determinants. Staff witness Valcarenghi testified that this approach presents a matching problem since rate base and expenses are reflected for the year ended May 31, 1992, while utilizing July 31, 1990 demand and energy consumption levels.

Staff's second method would require that BSU-2 revenues be determined by considering more current billing determinants. Mr. Valcarenghi testified that using updated billing determinants is a "means of mitigating the mismatch" that is "inherent in the first approach" and would reduce "impact on ratepayers because of a greater base over which to allocate the costs."

Under Staff's third method, total BSU-2 revenue requirements, less the incremental revenues after the end of the test year, are divided by updated billing determinants. This is Staff's preferred method. Like the second surcharge proposal, the third method mitigates the matching problem. In addition, Mr. Valcarenghi opines that the third method is most consistent with Commission precedent.

BSU-2 costs would be allocated to customer classes in the same way as other production plant. Like BG&E's purchased capacity surcharge, Staff would then recover class costs on a

per kilowatt-hour ("kWh") basis for customer classes without demand charges and a per kW basis added to the production and transmission demand charge for those classes with demand charges. However, Staff does not object to imposing both a demand and energy charge on demand classes; and Staff sees merit in seasonal differentials, and in using the BSU-2 increase to move customer classes closer to the system return.

Various parties raise objections to surcharges generally, and to particular aspects of Staff's three methods. Some say that any surcharge is single issue ratemaking, isolating one aspect of the revenue requirement from all others. Others liken a surcharge to using a forecasted test year. Still others cite the matching principle, or assert that, because traditional methods provide a lower level of cost recovery, a surcharge is unjustified. One party contends that, if Staff's "interim surcharge" is adopted, a true-up mechanism will be needed.

Another objection to Staff's surcharge is that its calculation includes BG&E's adjustment for additional O&M expense. Some object to BG&E's inflation escalator of that item. OPC also suggests that the proposed level of O&M expense does not reflect the economies of operating two similar plants.

Among the surcharge proposals, there is considerable disagreement about the relative merits of the second and third methods. BG&E witness Brady continues to favor a phase-in of BSU-2 costs; but if the Commission accepts Staff's proposal, he

advocates the use of the second surcharge method. OPC witness Gallagher favors a traditional, albeit expedited treatment of BSU-2 costs; yet, of the surcharge proposals, he prefers the third method since it includes a sales adjustment.

Mr. Gallagher agrees that the circumstances of this case are "unique," and may justify a departure from typical rate-setting methods. Among other things, he notes that "the analysis of other elements affecting base rates is reasonably current...." However, the witness agrees with Staff's reading of prior cases and characterizes the third method, with its sales adjustment, as a "reasonable second-best alternative" to a full rate case.

Mr. Brady opines that the third method is "distorted" because it reflects "forecasted sales and revenues to be recognized subsequent to the test year, but ignores changes in expenses and rate base other than changes related to Brandon Shores Unit 2." In other words, the witness insists, the third method "mistakenly assumes that any increased revenues would be exclusively available to offset future operating expenses associated with Brandon Shores Unit 2." He also maintains that Staff misreads the precedent on this issue.

Many parties have cost allocation and rate design concerns. Beth Steel contends that its surcharge would be higher than its current non-summer month production and transmission demand charge, an "erroneous result." It also asserts that a surcharge will cause an overrecovery because of the

recent outage of the "L" furnace. Finally, Beth Steel notes that a time differentiated seasonal factor and a kWh factor are used to allocate costs, while Beth Steel's surcharge is a constant nonseasonal demand charge.

OPC suggests that the allocation proposed by Staff is unfair because it does not "coordinate the effects of the surcharge and fuel savings." Others argue that Staff is too simplistic in its treatment of classes with demand charges. Many say that a surcharge will undermine the goal of moving class rates of return closer to the system average. There are alternatives, several parties say, that are not so fraught with cost allocation and rate design problems.

One such alternative is a second step, base rate adjustment. In lieu of an "interim" surcharge, base rates would be increased first to recover non-BSU-2 costs and again to cover BSU-2 at the time of commercial operation. Although the labels are confusing, a second step base rate is much like a surcharge, but it is not a temporary measure. Instead, the step increase simply accelerates the roll-in to base rates. Although usually denominated a "surcharge" in past proceedings, the Commission has authorized such an adjustment to base rates in cases where the purpose was to reflect the costs of a permanent rate base addition, without the need for subsequent true-ups.

A step rate method, if done properly, minimizes any cost allocation and rate design problems. Instead of allocating BSU-2 to classes based on the 4CP Min/Max method without

regard to the effect on class returns, additional revenue requirements from both the non-BSU-2 and BSU-2 portions of the case could be assigned in a manner similar to BG&E's method. Thus, an effort would be made to move the customer classes closer to the 7 percent band, followed by an increase in proportion to base revenues. Also, a crude flat kW or kWh rate would be replaced by seasonal rates and other base rate-like designs (such as both kW and kWh rates for demand classes).

After carefully considering the evidence and argument on the issue of Brandon Shores, we reach two primary conclusions. First, we find that it is in the public interest to reflect in rates both the costs of BSU-2, and the projected fuel cost savings, in a timely fashion. Second, we conclude that a step rate approach, with the revenue requirements and updated billing determinants of Staff's second method, is the best way to reflect BSU-2 costs in base rates.

We define timely here as coincident with the date of commercial operation, now estimated at June 1, 1991. Some argue that we should wait until BG&E files a new base rate case to consider the issues. But since most facts about BSU-2 are known and certain at this time, a full rate case, whether expedited or not, is unnecessary. Also, because we will order a revision in the fuel rate when BSU-2 goes into service, it is only appropriate to reflect the costs that produce those savings at the same time.

In reaching this decision the Commission observes that the evidence in this proceeding is clear that the capital costs of BSU-2 are reasonable. The plant, which is substantially complete, will cost about $662 million, or $1,031 per kW, nearly 20 percent less than a typical coal-fired plant of that size. Next, no one disputes BG&E's testimony about the need for this unit, which is not surprising, given recent load growth. Finally, the record is uncontradicted that BG&E's management of the BSU-2 project was prudent. With few facts left to determine, the creation of a separate and expensive proceeding, we believe, would be unnecessary and not in the public interest.

As we said at the outset, the principal issue is not whether to reflect the increased revenue requirement of BSU-2; the questions are when and how. BG&E prefers a phase-in of costs, beginning on January 1, 1991. After reviewing the many objections to this proposal, it is obvious that the intended beneficiaries of the Company's proposed "gradualism" in rate increases reject the treatment proposed by BG&E. We do not agree, however, with each and every objection to a phase-in. Rather, we note simply that the net rate effect of BSU-2 is not large enough to warrant the extraordinary remedy of a phase-in, given the objections of the representatives of the affected customer classes who are parties to this proceeding.

Similarly, we are not satisfied that the use of deferred accounting is a proper approach to reflect BSU-2 costs. GM concedes that its proposal will increase the BSU-2

revenue requirement in 1992; yet it argues that such an increase "is not necessarily detrimental to atepayers." We agree with GM that whether such an increase is detrimental is a function, in part, of a ratepayer's cost of capital. Unlike GM, however, we are unwilling to assume that most ratepayers have a higher cost of capital than BG&E. Thus, without deciding all questions about deferred accounting, we decline to accept the proposal in this proceeding.

Thus, we opt for a rate adjustment coincident with the in-service date of BSU-2 based on one of Staff's methods to determine the additional revenue requirements. No party urges us to use Staff's first method, and we do not consider it further. We are persuaded, however, that Staff's second method offers an equitable and reasonable way to compute the BSU-2 revenue requirement.

We agree with Staff witness Valcarenghi that his second approach is a "means of mitigating the mismatch" that is "inherent in the first approach." By using updated billing determinants we mitigate any mismatch and customer impact. By rolling the revenue requirements into base rates we are also able to accommodate an appropriate rate design.

Some parties argue that precedent supports the use of a revenue adjustment in the calculation of the BSU-2 revenue requirement. The Company opposes such an adjustment, arguing that a predetermined revenue requirement may fail to take into account increases in expenses other than those associated with

BSU-2. For that reason, in general, the Commission does not make sales adjustments in electric rate cases. Re Delmarva Power & Light Company, 74 Md. PSC 566, 573 (1983).

Some parties also cite Re Potomac Electric Power Company, 78 Md. PSC 168 (1987) for the proposition that a revenue adjustment is appropriate in this case. However, we believe that reliance on that case is misplaced, for two reasons.

First, unlike Staff's third method, the adjustment in Case No. 7972 was not a pure revenue adjustment. Rather, the Commission adjusted income for the "earnings growth per unit of sales growth" in a post-test year period. Id. at 181. Thus, the Pepco adjustment was not a sales adjustment, and the Commission explained why it rejected the latter. An unadulterated sales adjustment "takes no account of the growth in certain expenses, not otherwise included in ratemaking adjustments, which is an inevitable result of sales growth." Id. at 180.

The Pepco case is distinguishable for another reason. The incremental earnings adjustment was predicated, in part, on "extraordinary growth in sales" in the post-test year period. Id. Among other things, the data showed that sales growth in Maryland in 1986 was a stunning 7.7 percent, and that sales in the six months after the test year rose by 442,404 MWh. In contrast, there is no evidence here of such robust growth in sales, either actual or forecasted.

We have carefully considered the arguments by the parties on this issue and conclude that under the circumstances of this case a predetermined revenue adjustment may not be justified. We will, however, evaluate the need for a June 1, 1991, rate adjustment through the methodology described below.

By this Order, we authorize BG&E to file revised tariffs, along with a revised fuel rate, to become effective when BSU-2 enters service, on or about June 1, 1991. The new rates will be contingent on the following events. First, BG&E must show that, absent a rate adjustment, it will be otherwise unable to earn its authorized return. That showing must be made in the manner that was recommended by Staff, based on the March 31, 1991 quarterly report, the most recent data available before the in-service date. Second, if operating results indicate that BG&E has been earning more than its authorized return, but not enough to absorb the BSU-2 revenue requirement, the rate adjustment will be limited to a level of revenue requirements that provide the Company an opportunity, prospectively, to earn at the level of its authorized return, rather than the full amount of BSU-2 revenue requirement. Finally, BG&E must furnish the data that is necessary to calculate the revenue requirement, which should not vary in any significant way from the evidence in this case.

As a part of the BSU-2 revenue requirement, BG&E reflects a $14 million adjustment for O&M expense to run the new plant. This figure is an estimate based on the expense of

BSU-2's sister unit. Some parties object to the adjustment because it includes an inflation escalator. Also, Mr. Gallagher believes that the number does not reflect the "expected economies" in operating two similar plants, so he reduced the figure to 75 percent of the Brandon Shores Unit 1 amount.

We find that the $14 million adjustment is reasonable. Granted, BG&E escalates the expense for inflation. However, the expense on which the adjustment is based is a stale 1989 figure. The escalator merely transforms the 1989 expense into a 1991 amount, to reflect conditions that can be expected to be experienced when BSU-2 is operational. Also, the inflation factor is a reasonable 4 percent per year (8.16 percent for two years). Lastly, contrary to OPC's belief, BG&E reduced O&M expense for expected economies in operating two plants; but it found a 10 percent savings, versus OPC's larger, seemingly arbitrary reduction. Accordingly, we accept BG&E's O&M adjustment.

BG&E shall file the required BSU-2 information and tariffs with the Commission and all parties to this case in a timely fashion. We expect that review will be similar to that which occurs upon a compliance filing. We also expect to consider the filing at an administrative meeting, at which all parties will have an opportunity to express their views as to whether there is compliance with this Order. Among other things, the tariffs shall implement our rate design decisions hereinafter.

By making the use of a step rate contingent on a showing that BG&E will be otherwise unable to earn its authorized return, we follow the approach in Case No. 8208. In addition, we obviate the need for an adjustment for any increased sales in the post-test year period by limiting the increase as discussed above. If revenue growth increases greatly from the test period to the 12 months ended March 31, 1991, the effect is to increase earnings (all other things equal).[2] If earnings exceed the level of the authorized return, BG&E will be limited in the level of the BSU-2 rate increase. Thus, ratepayers will be protected.

While base rates may increase by about $124 million if the rate adjustment takes effect, there would also be a simultaneous adjustment to the fuel rate which, in part, will offset the base rate increase. BG&E now estimates that generation from BSU-2 will cause an annualized fuel cost reduction of $52 million. However, if the price of a barrel of oil rises substantially from the numbers in BG&E's filing, BSU-2's generation will replace the need for more costly production, reducing the fuel costs which otherwise would be incurred by a

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[2] Some argue that a problem with the use of the quarterly report is that the cost of capital may decline. But that is true when we set a rate of return in any case. We recognize that the cost of capital may change, for it changes daily in the financial markets. Still, when we set a rate of return for the rate-effective period, we do not expect that the component costs of capital will not change. Rather, we expect our over-all number to be fairly representative.

larger amount. Of course, the offset will not be known until the spring of 1991, when the fuel rate formula will be synchronized to reflect on a timely basis the annual fuel cost savings associated with the operation of BSU-2.

III. RATE BASE

BG&E's unadjusted electric rate base is almost $3.9 billion. The per books figure must be adjusted, however, to determine the "fair value of the company's property used and useful in rendering service to the public."[3] After making such adjustments, the Company proposes an electric rate base of nearly $4.1 billion. Other parties, who sponsor or support a variety of adjustments, arrive at a lower valuation.

All parties reflect unamortized gains on the sale of real estate, and no one questions OPC's Keystone and Conemaugh inventory adjustment. Similarly, there is no real dispute about cash working capital: the amounts vary from party to party, but not because of principles; rather, the recommended rate relief, income adjustments, rate base and capital costs explain the differences. Thus, our cash working capital will differ too. In the following discussion, we resolve the remaining issues about rate base.

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[3] Md. Ann. Code, art. 78, §69(a).

A. Average Or Terminal Rate Base

BG&E proposes the use of a terminal rate base, an adjustment of $178 million. According to Mr. Brady, BG&E has and will experience "the unprecedented combination of record levels of capital requirements and severely eroding earnings." A terminal rate base is necessary, he says, to combat attrition. Some projects, such as reinforcements to distribution and transmission systems, do not bring sales growth. Mr. Brady expects many such projects soon; he foresees an imbalance between rate base and sales growth.

Citing precedent, all other parties urge us to use an average rate base. In Re Baltimore Gas & Electric Company, 71 Md. PSC 249, 254 - 255 (1980), we said:

> Proper rate making requires that revenues, expenses and investments be measured on a comparable basis. If a year-end rate base is utilized, the company's test year revenues and the associated variable operating expenses should be adjusted to reflect the year-end number of customers and the trend in customer usage patterns that is evident at year-end or expected in the near future.

As BG&E adjusts rate base only, the other parties invoke the matching principle and reject the Company's proposal.

BG&E argues that, while an average is favored generally, precedent does not foreclose the use of a terminal rate base. Instead, the issue has been decided on a case-by-case basis. The Commission has used a terminal rate base when the

"record has clearly established substantial need," Re Maryland Marine Utilities, 76 Md. PSC 564, 567 (1985), after a consideration of the "total financial evidentiary picture," Re Southern Maryland Electric Cooperative, Inc., 72 Md. PSC 218, 219 (1981), and upon a showing that a construction program is substantial, and will not produce revenue. Re Maryland Water Works, 74 Md. PSC 221, 224 (1983).

After considering this issue, we conclude that an average rate base is appropriate for use in this proceeding. In those cases where the Commission has used a terminal rate base, the evidence was persuasive that attrition was likely during the rate-effective period; the record showed that, more likely than not, the expected growth in revenues would not exceed that of rate base and expenses.

The evidence in this case indicates that the terminal rate base exceeds the average by $178 million, of which $108 million represents an increase in CWIP. (We note that the Company is not proposing a corresponding adjustment to AFUDC.) A substantial portion of this increase in terminal rate base undoubtedly is due to the continuing construction of Brandon Shores Unit No. 2 which, in accordance with this Order, will be accorded terminal rate base treatment as plant in service as of June 1, 1991. Furthermore, in this proceeding we accept the Company's proposed adjustment to AFUDC for property additions placed in service by January 1, 1991. These factors will favorably impact on any rate base attrition that may occur

during the rate-effective period. While we do not rule out the use of terminal rate base in a proper case, we are not persuaded on the basis of this record.

The parties' opposition to the acceptance of a terminal rate base rests mainly on an argument that acceptance of a terminal rate base would require that revenues and expenses be measured on a comparative basis, including the year-end number of customers and the trend in customer usage patterns. Staff's witness notes that the use of a terminal rate base, by itself, is an incomplete correction for the effects of attrition. We can see merit in the parties' arguments. We can also see, however, the real potential for attrition that may be experienced under various conditions during the rate-effective period.

While we, therefore, do not find that BG&E has provided that substantial evidence of attrition that would justify acceptance of a terminal rate base in this proceeding, we recognize that an increase in capital expenditures on non-revenue producing projects, as well as inflationary pressures, could disprove the general theory of balanced growth in revenues, expenses and rate base and the conclusion that proper matching of these elements will result in just and reasonable rates for a rate-effective period.

We have carefully considered the matter and tentatively conclude that the answer to this dilemma may be found in a more favorable receptivity to a forecasted test year than has

generally been exhibited by this Commission in recent years.

At the present time, while the selection of a test year is the prerogative of a company initially, the Commission requires that prefiled test year data should include, in addition to any other test year that may be proposed by the company, test year data based on actual operating results. If the company opts for a partially forecasted test year for which actual operating results for the forecasted period will become available within a reasonable time after the original date of filing, no additional fully historic test year data must be filed. Re Delmarva Power & Light Company, Case No. 7427, Order No. 64497, issued on November 5, 1980 (unpublished).

If, however, the company bases its application on a fully forecasted test year, the utility was advised to file, in addition, data for the most recent 12-month period for which actual operating results are available.

Since the adoption by the Commission of this policy, affected utilities applying for a change in rates generally have opted for the partially forecasted test year that has been accepted by the Commission. No fully forecasted test years have been proposed during this period. We assume that no such filings have occurred, in part, because of the Commission's stated concern over the reliability of forecasted test year data and its preference for the acceptance of actual results of operations.

In light of various arguments in this proceeding, we have reviewed our test year policy and the implications of such policy for ratemaking results in proceedings such as the one before us. While we do not plan to change the filing requirements that are set out in our policy statement, we want to clarify, however, that we are willing to consider, subject to a proper evidentiary presentation, a forecasted test year for the purpose of ratemaking under the appropriate circumstances. We will still require the filing of actual results for an historic period for comparison purposes, but will consider for evidentiary evaluation forecasted data for the purpose of determining just and reasonable rates for a prospective rate-effective period in a given case.

B. Load Management Capital Expenditures

BG&E adds $5.2 million to rate base to reflect the estimated cost of radio control switches for its air conditioning ("a/c") and water heater load management programs. In 1991, BG&E expects to install switches on an additional 30,000 air conditioners and 12,000 water heaters. While water heater control is new, the a/c program has been very successful and is evidence of the potential of load control. According to Mr. Hargest, the number of a/c customers has risen "from 18,300 in July, 1989 to about 75,000 by July, 1990, and . . . [may climb] to over 105,000 by the summer of 1991."

All parties except OPC accept the Company's adjustment. OPC excludes the item from rate base because the expenditures are based on budget projections for 1991, and the Commission "typically excludes post-test year adjustments." On brief, OPC insists that the Commission should encourage conservation; but it suggests that, before we grant "non-traditional treatment" of demand-side management (DSM) costs, the Company should demonstrate that "it will do more than simply talk about aggressive conservation programs." OPC also suggests that we wait for a report from a task force that we established to study ways to encourage DSM options.

OPC witness Chernick testified at great length about BG&E's DSM efforts, and finds them deficient. The witness opines that "BG&E has not properly analyzed DSM potential or economics." Among other things, he suggests that the Commission should order BG&E to "begin readying demand-side options in time to compare and compete with the supply it would otherwise acquire over the next decade."

While we understand OPC's position on the radio control switches, we disagree. Assuming arguendo that BG&E's DSM efforts are insufficient, it would be counterproductive to withhold inducements. We want to encourage conservation now, and send a clear message to that effect. If we urge BG&E to implement DSM programs forthwith, and then impede the recovery of costs, our signals will be conflicting, the message garbled. DSM programs should not be hindered, and the objective justifies some departure from rigid rules of ratemaking.

We take OPC's charges against BG&E seriously. Nevertheless, as stated from the bench at the hearing, this is not the appropriate case for an in-depth review of integrated resource planning. There are other fora in which to effectively address the issues about BG&E's DSM efforts. The task force is one such possibility; Case No. 8241 is another.[4]

In the meantime, we are faced with a choice of wielding a stick when it may not be justified, or dangling a carrot until the verdict is in. We prefer the latter approach. Clearly, conservation is in the interests of participating consumers, other ratepayers and the citizenry in general. We would like to make it more appealing to investors as well. Accordingly, we accept the Company's adjustment.

C. Deferred Fuel Balance

In BG&E's last two base rate proceedings, we resolved a number of issues about the working capital allowance for BG&E's deferred fuel balance consistent with the requirements of Section 54F for the recovery of fuel costs by BG&E. In those decisions, we set rates that reflect a 13-month average balance, net of taxes, for the period ended April 30, 1989.

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[4] In lieu of litigating these issues, we encourage BG&E to engage in a collaborative process with interested parties, including consultation with BOMA.

That period is the test year in Case No. 8190, but the selection of the deferred fuel balance is significant for another reason.

In Case No. 8208, we explained that April 1989 is the approximate beginning of the extended outages at Calvert Cliffs. Thus, the April 1989 deferred fuel balance reflects "the level that existed prior to the escalation of such balances primarily due to the Calvert Cliffs shutdown." Re Baltimore Gas & Electric Company, 80 Md. PSC 496, 502 (1989). In Case No. 8208, BG&E had asked us to reflect the new test year amount, a larger balance for the period ended August 31, 1989, but we declined.

In this proceeding, BG&E renews its request for a return on the deferred fuel balance in the most recent test year. Thus, in its calculation of the revenue requirement, BG&E reflects the 13 month average balance of deferred fuel for the period ended July 31, 1990. That balance, net of taxes, is almost $207 million, about $154 million greater than the amount that was reflected in the last two rate cases. Staff accepts the Company's adjustment, but all other parties reflect the pre-Calvert Cliffs shutdown level of deferred fuel.

In Case No. 8208, we said that if any future disallowance of fuel costs exceeds the rate base exclusion, then interest will be added to the disallowance, and ratepayers will be made whole. BG&E reasons that this treatment is one-sided: stockholders do not earn a return on the actual deferred fuel

balance, which is much greater than the level in rates; and even if the Commission finds ultimately in BG&E's favor, stockholders will never recover the interim financing costs.

We are not persuaded to reverse our decisions in BG&E's last two rate cases. The selection of the pre-Calvert Cliffs shutdown level of deferred fuel, and not some higher or lower amount, reflects a balancing of interests:

> In our decision, we accommodate the principle that an asset that is ultimately found to have been imprudently incurred should not be permitted to earn a return. It is also based on the equitable considerations of the length of time which may pass before litigation of the issues raised under Section 54F(f)(4) will be completed, and the existence of the long-standing deferred fuel balance. Id.

As a part of this balancing process, we rejected an argument that no allowance should be made for deferred fuel. BG&E overlooks that fact, and that, whatever temporary financing costs are borne by stockholders, rates reflect some of those costs and a return on and of nuclear plant. BG&E objects to the fairness of the decision in Case No. 8208, but it did not ask for rehearing or file an appeal. We see no reason to reconsider the issue now.

After adjusting the deferred fuel balance to the April 1989 level, OPC witness Gallagher reduces it by another $5 million to "reflect the continuing amortization reflected in the Fuel Rate." BG&E witness Bange did not accept this

adjustment because, at the time of his pre-filed testimony, the fuel rate surcharge was expected to expire before the rate-effective period. Subsequently, at an administrative meeting, the Commission approved BG&E's request for a continuing surcharge. We note that BG&E agrees to an amortization in its application for a surcharge, and we accept OPC's adjustment.

D. Deferred Nuclear Projects

In Case No. 8208, the Commission capitalized the "startup or foundation" costs of the following four nuclear projects: Configuration Management Project, Procedure Upgrade Program, Procurement Program and Nuclear Information Project.[5] In this case, OPC proposes to remove $7.5 million from rate base, a part of the deferred costs. According to Mr. Gallagher, OPC's consultant determined that a "portion" of the projects' costs were unreasonably incurred. Therefore, Mr. Gallagher deducts "the average test year value for the unreasonably incurred deferred project costs."

Consistent with our discussion of nuclear O&M expense, we decline to reverse the prior capitalization of deferred nuclear projects. However, we do adjust rate base to reflect the unamortized balance of the pressurizer heater sleeve repairs.

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[5] Re Baltimore Gas & Elec. Co., 80 Md. PSC 496, 507 (1989).

E. Finding

After reflecting the aforementioned adjustments to per books figures, and the cash working capital requirement that is consistent with our decision, we find that the fair value of the Company's property that is used and useful in rendering electric service to the public is $3.729 billion. (See Appendix A.)

IV. NET OPERATING INCOME

The Company has proposed several adjustments to its test year operating results which have not been contested by the other parties. Since these adjustments are consistent with the criteria established by the Commission, they will be accepted for ratemaking purposes in this proceeding. The remaining adjustments which are at issue will be considered at this point and will be made net of tax. (See Appendix B for all adjustments to net operating income.)

A. Corporate Performance Awards

In Case No. 8190,[6] the Commission adopted a Staff-proposed adjustment that normalized an unusually high test year corporate performance award expense; instead of the test year

[6] Re Baltimore Gas & Elec. Co., 80 Md. PSC 380, 397 (1989).

amount, a four-year average was used. The Company's proposed adjustment in this case updates the four-year average level of this expense, decreasing test year income by $517,000.

Staff takes the position that the Company's averaging adjustment is unnecessary in this case. Staff witness Webster reviewed the past several years of this expense and determined that, if the aberrational level for this item in 1988 is ignored, the test year expense of $2.291 million was "normal." The witness further observes that if the higher, average figure is used, rates would reflect a higher corporate performance expense while results (as measured by employee goals) were significantly lower, based on the actual test year level.

In rebuttal, Company witness Bange acknowledges that the actual test year expense for this item was less than the four-year average. He contends, however, that in order for the Company to recover its costs over time, the Commission must use the averaging process consistently; he cites the Commission's handling of storm damage expense as an example of the averaging treatment.

Approximately 14 months ago, in Case No. 8190, the Commission accepted an adjustment to normalize BG&E's corporate awards expense based upon Staff's concerns regarding the volatility of this item. In that case, we used a four-year average to normalize the test year level. We find it appropriate to continue that treatment herein, even though the test year amount in this case may not be out of line. Based upon the

Company's prior experience, we assume that in future years, this account may again be volatile. Accordingly, we will accept the Company's adjustment.

B. Tariff Changes from Case No. 8208

Both Staff witness Valcarenghi and OPC witness Gallagher maintain that the Company has incorrectly quantified the impact of the tariff changes authorized by the Commission in Case No. 8208. According to these witnesses, the Company's adjustment was based upon the incremental revenue the new rates produced during the 7½ months the new rates were in effect, subtracted from the $21.474 million increase authorized in Case No. 8208. Such an approach, Mr. Gallagher testified, assumes that only an additional $21.474 million would have been received during the current test year, an incorrect assumption since increased billing determinants in the current test year would result in more than $21.474 million of increased revenues.

Staff and OPC contend that in order to properly annualize the impact of the tariff changes, the test year sales levels should be taken into account. However, Mr. Valcarenghi and Mr. Gallagher take a somewhat different approach in calculating their respective recommended adjustments.

Staff witness Valcarenghi took the Company's actual aggregate sales volumes from August 1, 1989 through December 18, 1989 (that portion of the test year during which

the new rates were not in effect), and repriced them using the rates approved in Case No. 8208. He then compared the result to the Company's actual aggregate book revenues for that same period. The difference between the two figures is his recommended adjustment ($5.863 million) to operating income.

In contrast, OPC witness Gallagher applied the rates authorized in Case No. 8208 to BG&E's billing determinants (i.e., kW, kWh, customers, etc.) for the period August 1, 1989 to December 18, 1989. These results were then compared to actual revenues received at the old rate levels. The difference between the two ($5.523 million) is his recommended annualization to reflect a full year of revenues at the new tariff rates.

On brief, the Company argues that the approach proffered by Staff and OPC "involves the retroactive use of a calculation of hypothetical revenues which theoretically would have resulted if the revised tariffs had been in effect for the full test year." The Company maintains that reflecting only actual, known amounts is preferable in this context.

Having considered the evidence regarding this issue, we find that BG&E's adjustment does not accurately reflect the increased revenues which the Company is receiving pursuant to our decision in Case No. 8208. As between Staff's and OPC's proposed adjustments, we find that use of the Company's actual billing determinants in calculating this adjustment will more

accurately reflect the tariff changes authorized in Case No. 8208. Accordingly, we will accept OPC's adjustment to increase test year operating income by $5.523 million.

C. AFUDC Accrual

1. On Property Placed in Service

The Company has proposed an adjustment to eliminate accruals of Allowance for Funds Used During Construction ("AFUDC") on those construction projects for which AFUDC will not be recorded during the rate-effective period. A portion of this adjustment relates to construction projects completed and placed into service during the test year. The remaining portion eliminates AFUDC on construction projects scheduled to be completed and placed in service between the end of the test year and the start of the rate-effective period. The Company asserts that failure to adopt this adjustment would deny the Company an opportunity to earn a return on $31 million of plant which will be in service as of the date of this Order. Company witness Bange states that, with the cessation of AFUDC accruals on these projects, the Company's earned rate of return will be immediately impacted if the proposed adjustment is not reflected. Staff accepts the proposed adjustment.

OPC witness Gallagher characterizes this adjustment as an attempt to recognize a level of plant in service in excess of the test year average. Both he and GSA witness Prisco recommend that the Commission continue its policy of rejecting adjustments to proform rate base beyond the test year.

Similar adjustments have been proposed in previous BG&E base rate applications, but have been rejected by the Commission. While the Commission noted in Case No. 8208 that an adjustment to a test year average rate base may be appropriate where sizeable plant additions substantially alter test year relationships,[7] we have rejected proposed adjustments regarding post-test year AFUDC for CWIP which were not project specific on the basis that the adjustments represented AFUDC for CWIP levels which were recurring. The Commission found that such adjustments would constitute an allowance for attrition, the need for which had not been demonstrated.

In this proceeding, BG&E is urging the Commission to accept a terminal rate base instead of an average rate base in determining the Company's revenue requirement; the difference between the two is $178 million. If an average rate base is adopted, the Company asserts that it will experience earnings attrition. As more fully discussed above, we have rejected the use of a terminal rate base as a means to address attrition in this case. We do recognize, however, the potential for some attrition, especially with respect to new plant, unrelated to Brandon Shores, which will be providing service to customers throughout the rate-effective period. Accordingly, based upon the record in this case, we will accept the adjustment to reduce test year AFUDC as requested by the Company.

[7] Re Baltimore Gas & Elec. Co., 80 Md. PSC 496, 511 (1989).

2. All Construction Work In Progress

In Case No. 7770, the Commission determined that BG&E need not accrue AFUDC on projects costing less than one million dollars nor those placed in service during the test year.[8] In this case, GSA witness Prisco proposes that AFUDC be accrued on the average of all of BG&E's test year construction projects, not just major projects. Such an adjustment would add $12.381 million to test year operating income.

In rejoinder, Company witness Bange maintains that Mr. Prisco did not provide any rationale to support a departure from the Commission's policy of accruing AFUDC only on major construction projects. Substituting AFUDC for a cash return on smaller projects would, according to the witness, adversely impact the Company's cash flow and increase the already significant level of external financing requirements.

The Commission's policy of accruing AFUDC on CWIP is based upon a balancing of the equities between present and future ratepayers. That only major projects are reflected recognizes "the fact that certain construction projects are of such a short duration or for such a relatively small amount of money that no AFUDC would be accrued."[9] GSA has provided no evidence that this policy is incorrect or inequitable. We, therefore, reject GSA's proposed adjustment.

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[8] Re Baltimore Gas & Elec. Co., 75 Md. PSC 171, 190 (1984).

[9] Re Baltimore Gas & Elec. Co., 74 Md. PSC 249, 273 (1983).

D. Wage Increases 1990/1991

The Company proposes an adjustment which reflects the remaining impact on the test year of a wage increase which went into effect in May 1990, as well as an increase which is expected to take effect in May 1991. Because the May 1991 wage increase will cover eight months of the rate-effective period (calendar year 1991), BG&E asks that an adjustment to annualize the 1991 wage increase be included in determining rates herein.

All parties accept that portion of the Company's adjustment which reflects the May 1990 wage increase. However, both OPC and MIG argue against adjusting the July 31, 1990 test year to include the May 1991 wage increase.

OPC witness Gallagher testified that because the latter wage increase is anticipated to occur ten months beyond the test year and five months beyond the order in this case, a mismatch with test year levels of operations would occur. He also notes that during the course of this proceeding, the Company has already reduced the anticipated wage increase from four percent to three percent, an indication to him that the adjustment is not known and measurable. Finally, in light of his recommendation that the Company file a rate case in 1991 to reflect the in-service date of Brandon Shores Unit 2, he believes the May 1991 wage increase should be considered at that time.

In a similar vein, MIG witness Falkenberg testified that adjustments for both the 1991 wage increase and the postage rate increase are "one-sided attrition allowances" which

should be rejected. He also observed that both adjustments are outside the test year and not known and measurable. Like OPC witness Gallagher, he recommended such adjustments be addressed in a 1991 rate case.

In numerous prior Commission cases, we have accepted pro forma adjustments for wages which will be incurred by a company during the first year revised rates are in effect. As we stated in a 1983 case involving The Chesapeake and Potomac Telephone Company of Maryland, "the crucial aspect of the issue . . . is 'whether the adjustment provides a fair representation of conditions as they will exist during a reasonable future period.'"[10] Consistent with our past decisions, we find that the proposed adjustment will reflect the wage increase which will occur during the rate-effective period.

E. Health Care

BG&E has proposed an adjustment to reflect known increases in its health care expenses related to health maintenance organizations and to Blue Cross/Blue Shield. The adjustment annualizes the remaining effect of increases in these health care expenses actually experienced by the Company during the test year. With the exception of Staff, all other parties accept this adjustment.

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[10] Re Chesapeake and Pot. Tel. Co. of Md., 74 Md. PSC 21, 34 (1983), citing Re Chesapeake and Pot. Tel. Co. of Md., 73 Md. PSC 181, 201 (1982).

Staff witness Webster recommends rejecting that portion of the adjustment related to payments to Blue Cross/Blue Shield. Mr. Webster cites a data response by the Company which states that "[t]he increase in Blue Cross/Blue Shield costs reflects the projected increase in health care costs used by Blue Cross/Blue Shield in the calculation of the Company's required payments . . ." According to Staff, the Blue Cross/Blue Shield portion of the adjustment should be rejected because it is based upon projections; as such, it is not a known and measurable expense supported by adequate documentation.

On cross-examination, Company witness Bange testified that BG&E has a contract with Blue Cross/Blue Shield in which the Company agreed, starting June 1, 1990, to pay 13 percent more per month for Blue Cross/Blue Shield coverage. According to Mr. Bange, the Company's health care coverage is a self-insured plan so that BG&E pays Blue Cross/Blue Shield an amount each month that is then compared to actual claims incurred. Based upon the Company's experience, the 13 percent increase was determined by both parties to be reasonable.

Having reviewed the evidence on this issue, we believe Staff has misconstrued BG&E's data response. The Company's adjustment simply annualizes actual increases in payments to Blue Cross/Blue Shield which occurred during the test period; as such, it reflects a known and certain change. Staff's position is, therefore, rejected.

F. Tree Trimming

In BG&E's last rate case, Case No. 8208, the Commission accepted a Company-sponsored adjustment to its test year tree-trimming expense to reflect projected expenditures during the rate-effective period. Acceptance of the adjustment was based in part upon an increase in this expense from the April 30, 1989 test year in Case No. 8190, to that in the August 30, 1989 test year in Case No. 8208, and in part upon Staff testimony regarding a 33-page Company study (submitted to Staff in a data response) showing that the Company's tree-trimming expenses were expected to increase.[11]

In this case, the Company has adjusted its July 30, 1990 test year tree-trimming expense to reflect the remaining effect of the adjustment accepted in Case No. 8208.

OPC witness Gallagher asserts that this adjustment should be rejected for two reasons: first, during the rate-effective period for Case No. 8208 (calendar year 1990), the Company's budget for this item is only $9.1 million rather than $9.335 million approved in rates by the Commission. Second, during the six months ended June 1990, BG&E underspent its budget by $352,000. In Mr. Gallagher's view, since the Company is not spending on tree trimming what the Commission authorized

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11 Re Baltimore Gas & Elec. Co., 80 Md. PSC 496, 512 (1989).

it to spend, use of the budget projection for 1990 in Case No. 8208 was inappropriate. He recommends that, in this case, the Commission use the test year amount for this item.

On rebuttal, Company witness Bange testified that actual expenditures during the first part of 1990 were below budget because the contractor retained by the Company was unable to provide a sufficient number of qualified work crews. He added that the Company presently expects to spend $9.3 million on tree trimming during 1991, the anticipated rate-effective period for this proceeding.

The actual test year experience of the Company with respect to this item calls into question the adjustment in Case No. 8208. We, therefore, decline to accept the remaining effect of that adjustment in setting rates herein.

G. Purchased Capacity Charges

In August 1988, BG&E entered into a two-part contract with Pennsylvania Power & Light Company ("PP&L"). The first part of the agreement involves the purchase of capacity (without associated energy) to satisfy BG&E's requirements as a member of the Pennsylvania-New Jersey-Maryland Interconnection. The second part involves the purchase of energy and capacity from PP&L's Susquehanna Steam Electric Station from October 1991 through May 2001. In accordance with the Commission's Order in Case No. 8208, the Company requested, and was granted, authority to recover the former by means of a base rate surcharge during the period June 1990 through May 1991.

The Company's proposed adjustment would eliminate the currently authorized capacity surcharge while annualizing the remaining portion of such charges in base rates. The adjustment would also reflect in base rates the first three months of the Susquehanna purchase which is scheduled to begin in October 1991, and, thus, falls partially within the anticipated rate-effective period.

Staff witness Davies, OPC witness Gallagher, and Beth Steel/GM witness Selecky oppose the Company's adjustment in toto. With respect to that portion of the proposed adjustment related to purchases of peaking capacity, Staff witness Davies observed that these costs are currently being recovered by a base rate surcharge. Since the surcharge is scheduled to continue only until May 1991, and since BG&E will not purchase any peaking-only capacity for the period June 1991 through May 1993, she believes it is unnecessary to change the current method of recovery. In Mr. Gallagher's view, reflecting any post-May 1991 surcharge revenue in base rates is inappropriate at this time.

While the proposed adjustment for peaking capacity purchases is consistent with our expressed preference to include capacity purchases in base rates, the purchase in question will end on May 31, 1991. Under these circumstances, and in light of this contemporaneous proceeding to determine otherwise just and reasonable rates, we agree with Staff and decline to change the currently authorized capacity surcharge

which will expire on May 31, 1991. The adjustment to base rates reflected in Mr. Hargest's exhibits, therefore, will not be necessary.

That portion of the proposed adjustment related to the purchase of capacity from Susquehanna beginning October 1, 1991, is also opposed by Staff, OPC, and Beth Steel/GM. Each, essentially, takes the position that it is inappropriate to reach 14 months beyond the test year and 10 months beyond the Commission's order in this case to include such an expense item without also recognizing increased sales.

Company witness Brady offered three alternatives to BG&E's original adjustment associated with the Susquehanna purchase. One alternative would be to leave the existing peaking capacity surcharge in effect through May 31, 1991, at which time it would be replaced by a Brandon Shores surcharge. On October 1, 1991, an additional surcharge related to the Susquehanna purchase could implemented. As with the current surcharge, the Susquehanna surcharge could be conditioned upon a showing that the Company would otherwise be unable to earn its autnorized rate of return. A second alternative would be to leave the existing peaking capacity surcharge in effect until October 1, 1991; the surcharge would then be increased to recover the Susquehanna purchased capacity costs which will begin to be incurred at that time. A third alternative, one not favored by the Company, would be to simply defer the Susquehanna costs until they can be authorized for recovery in a subsequent base rate case.

As we indicated in Case No. 8160, "[a]s a general rule, reliability capacity charges will remain as a cost component in base rates. A base rate proceeding provides for review of the total cost of service and constitutes the most effective means to establish overall just and reasonable rates."[12] We also noted, however, that,

> it is undesirable, cumbersome and inefficient to trigger frequent base rate proceedings which would be necessitated by frequently occurring changes in a utilities [sic] level of capacity purchases. We, therefore, do not foreclose some future modifications to our base rate policy to provide for interim relief where justified.[13]

Because the Susquehanna purchase will not begin until October 1, 1991, the Company's proposal annualizes only one-fourth ($12 million) of the related yearly purchased capacity costs ($50 million). Such an adjustment would not serve the Commission's intent to allow full recovery of capacity purchases (consistent with otherwise just and reasonable rates) without exacerbating the frequency of base rate filings. As a result, we believe that under the circumstances of this case, a conditional surcharge is appropriate.

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[12] Re Potomac Electric Power Co., 80 Md. PSC 93, 105 (1989).

[13] Id.

Using the criteria set forth in Order Nos. 68406 and 68611 in Case No. 8160, the Company may apply for a capacity surcharge at the time the Susquehanna capacity costs will be incurred. The Company must show that, based upon the actual ratemaking results of the Company's operations (as reported to the Commission in its quarterly reports), the Company would not be able to achieve its authorized rate of return without a surcharge.

H. <u>Nuclear Decommissioning</u>

The Company's proposed adjustment annualizes the presently authorized level of nuclear decommissioning expense and updates certain indices prescribed by the Nuclear Regulatory Commission ("NRC"). All parties accept these components of the adjustment. OPC witness Gallagher, however, takes issue with the method used by BG&E to compute the return on the prepaid accumulated deferred income taxes associated with the nuclear decommissioning reserve. According to Mr. Gallagher, the Company used a projected (i.e., 1991) value for accumulated deferred income taxes and ignored the impact of proforma interest related to the adjustment. Instead, Mr. Gallagher recommends using the test year average level of accumulated deferred income taxes, reflecting the tax effect of the interest associated with this implicit rate base addition, and using OPC's recommended overall rate of return, net of tax, as the rate of interest on internal funds.

On rebuttal, Company witness Bange accepts Mr. Gallagher's proposal to reflect the income tax effect of proforma interest associated with this implicit addition to rate base. He opposes use of the test year average level of accumulated deferred income taxes, asserting that because of ongoing deferred tax accruals, the actual accumulated deferred tax balance during the rate-effective period will exceed both the test year average level as well as the end-of-period balance. Further, he continues to use the rate of return recommended by the Company, net of tax, as the rate of interest on internal funds.

Having considered the arguments of the parties, we find that the end-of-period figure for accumulated prepaid deferred income taxes should be used, together with our findings regarding the appropriate overall rate of return, in calculating this adjustment. Use of an average figure as recommended by OPC would ignore the fact that the end-of-period balance of prepaid deferred income taxes is the lowest level the Company will experience during the rate-effective period. Our computation for this adjustment decreases test year operating income by $2.459 million.

Finally, in order to obtain a current tax deduction for the nuclear decommissioning accrual, the Company must file a private letter ruling request with the Internal Revenue Service ("IRS"). The IRS requires BG&E to compute the amount of the tax deduction requested for each unit based on the

assumptions utilized by the Commission to determine the amount of decommissioning expenses included in the cost of service. In order that BG&E may comply with the IRS requirements, the Commission has determined the following: the decommissioning cost of service for Calvert Cliffs Unit 1 is $4,993,739 and for Unit 2 it is $4,720,368. The assumptions upon which these costs are based include: the current dollar cost of decommissioning each of the Calvert Cliffs Units is $137,332,000; the estimated future dollar cost of decommissioning Calvert Cliffs Unit 1 is $465,054,905 and for Unit 2 it is $512,722,979; the after-tax rate of return is 7.5 percent for the qualified external decommissioning trust; and, contributions will be made to the qualified external trust on a quarterly basis.

I. <u>Postage Rates Increases</u>

In March 1990, the U. S. Postal Service requested a 20 percent increase in postage rates effective February 1991. According to BG&E, the request is currently pending before the Postal Rate Commission but is expected to be approved as requested. Company witness Bange notes that only once has the Postal Rate Commission recommended a lower postage rate increase than that which it was asked to consider, and in that instance, the Postal Service Board of Governors implemented the higher increase. As a result, the Company considers the proposed adjustment as known, certain and measurable.

Both Staff witness Davies and MIG witness Falkenberg recommend that, because a postage rate increase has not been approved, the adjustment is not known and certain and, thus, should be rejected.

The Commission recognizes that a postal rate increase has not as yet been granted; the evidence indicates, however, that in prior years, the level of increase requested by the U.S. Postal Service has always been granted. In light of this evidence, we believe the adjustment is appropriate.

J. <u>Annualization of Nonrecurring Excess Deferred Income Taxes</u>

The Company's proposed adjustment eliminates certain excess deferred federal income taxes ("DFIT") resulting from the Tax Reform Act of 1986, which decreased the federal income tax rate on corporations from 46 percent to 34 percent. Company witness Bange testified that the Company amortized the excess DFIT associated with the reduction in tax rates from 46 percent to 40 percent from June 1987 through May 1989, and that associated with the further reduction in tax rates from 40 percent to 34 percent from January 1988 through December 1989. Since a portion of this latter amortization is included in test year figures, the Company's adjustment eliminates the test year amount as a nonrecurring item.

According to OPC witness Gallagher, the Company's adjustment assumes that the ratemaking impact of the amortization of excess DFIT began January 1, 1988, and ended

December 31, 1989. Referring to previous Commission treatment of the amortization of excess DFIT, Mr. Gallagher recommends that, for ratemaking purposes, the beginning of the two-year amortization period be made to coincide with the order date in Case No. 8208 (December 1989), and the adjustment confined to the difference between the 36 percent tax rate and the 34 percent rate.

On rebuttal, Company witness Bange reiterated his testimony that all amortization of excess DFIT was completed by the end of 1989. He further noted that the Commission recognized and accepted this treatment in Case Nos. 8190 and 8208 when it approved an adjustment to eliminate from those cases' test years the non-recurring amortization of excess DFIT.

Having considered the arguments of the parties, we find that BG&E's proposal is consistent with the uncontested adjustment accepted by all parties in the Company's last two rate proceedings. OPC has not provided sufficient evidence to show that our acceptance of the adjustment in those two prior cases was wrong.

K. <u>Annualization of BRESCO Capacity Payments</u>

In the Commission's Order in Case No. 8208, issued on December 15, 1989, recovery of BG&E's capacity payments to Baltimore Refuse Energy Systems Company ("BRESCO") was changed from the Company's Electric Fuel Rate to its base rates. OPC witness Gallagher testified that as a result of this change,

the Company's test year revenues only reflect 7½ months of BRESCO revenue, with the remaining 4½ months reflected in the Fuel Rate. His proposed adjustment adds to test year revenues an additional 4½ months of revenue from BRESCO.

On cross-examination, Mr. Gallagher agreed that all of the revenues from BRESCO, whether in base rate⁻ or the Fuel Rate, are reflected in book income for the test year. He continued to assert, however, that beginning when BRESCO revenue was removed from the Company's Fuel Rate, BG&E was left with only partial BRESCO revenues on a prospective basis. In his view, an adjustment to annualize revenues "to what they would be" is necessary.

On rebuttal, Company witness Bange testified that BG&E's "actual" figures already include a full 12 months of BRESCO revenue and expenses so that OPC's adjustment is unnecessary.

Since Mr. Gallagher acknowledges that all BRESCO revenues are included in test year figures, we are not persuaded by his assertion that an additional adjustment is necessary. Accordingly, we will reject OPC's proposed adjustment regarding BRESCO revenues.

L. Uncollectible Accrual

Company witness Bange testified that in December 1989, BG&E increased its uncollectible accrual by $725,385 in order to ensure an adequate reserve balance for bad debts. In

the opinion of OPC witness Gallagher, there is no compelling evidence that the Company's reserve for uncollectibles was beginning to decline as a result of write-offs in excess of accruals. Accordingly, he recommends that the Commission reject the Company's adjustment.

Company witness Bange, on rebuttal, testified that because uncollectible accounts are a function of revenue, the level of bad-debt expense recognized in any 12-month period should reflect the expected level of uncollectible accounts inherent in the revenue recorded during that same period. The test year increase in the Company's bad debt expense accrual was based upon the level of uncollectible accounts which are expected to result from revenues recorded during the test period.

Having considered this issue, we accept the Company's justification for increasing its bad debt expense accrual during the test year. We agree that by increasing the accrual, future customers will not be unduly burdened with paying for prior uncollectible accounts.

M. Federal Income Tax - Uncollectible Reserve

OPC witness Gallagher testified that pursuant to the Tax Reform Act of 1986, the tax reserve for uncollectibles was to be taken to income over the four-year period 1987-1990. As a result, BG&E's test year figures include taxable income of $1.697 million and associated income taxes of $577,000 related

to this tax reserve item. Since, during the rate-effective period these amounts will not be included in income or income taxes, Mr. Gallagher removes the $577,000 included in test year income taxes. On cross-examination, Mr. Gallagher agreed that his adjustment would not be necessary if the Company had recorded an offsetting deferred tax deduction.

On rebuttal, Company witness Bange stated that an offsetting deferred tax decrease was recorded during the test year so that Mr. Gall[illegible]er's adjustment is not required.

Since th[illegible] has already recorded the offsetting deferred tax deduct[illegible]dentified by Mr. Gallagher, a further adjustment is unnecessary.

N. <u>Excess Overtime</u>

After reviewing BG&E's employee overtime levels over the past several years, OPC witness Gallagher deems the levels experienced during the test year to be both excessively high and non-recurring. According to Mr. Gallagher, during the first five months of the test year (August 1989 through December 1989), the ratio of overtime pay to base pay was 19.1 percent, while during the final seven months of the test year, the ratio was only 15.9 percent. His proposed adjustment would normalize employee overtime to a 16 percent ratio, equivalent to that experienced during the final seven months of the test year. While acknowledging that a similar adjustment was rejected in BG&E's last rate case, Mr. Gallagher noted that the increased

levels of overtime pay accepted in that case resulted from reductions in the number of BG&E employees. Because the number of Company employees has been rising since Case No. 8208, he believes a reduction in overtime pay is justified.

Company witness Bange responds that because work activities can occur seasonally, it is inappropriate to analyze overtime ratios based on less than a full 12-month period. He further asserts that the test year level of overtime is consistent with the levels experienced by the Company since 1988, and varies by less than five percent from the most recent full calendar year.

The Commission does not concur with OPC that the Company's overtime levels are either excessive or will be nonrecurring during the rate-effective period. Furthermore, we agree that because work activities can occur seasonally, it is inappropriate to analyze overtime ratios based on less than a full 12-month period.

O. Employee Bonuses, Incentives, and Gifts

OPC recommends an adjustment to test year figures for employee bonus, incentives and gifts. Mr. Gallagher observed that in Case No. 8208, the Commission ordered normalization treatment for the impact of corporate performance award payments because of the volatility of those payments and the inability to accurately project the anticipated rate-effective year level of such costs. Mr. Gallagher believes that five

additional bonus, incentive award, and gift programs exhibit similar volatility. For ratemaking purposes, he proposes a four-year normalization adjustment ($1.949 million) for the five programs, taken together, instead of the test year amount ($2.453 million).

On rebuttal, Company witness Bange acknowledged that the amounts for some of the individual programs "go up and down," but asserted that when you lump the various programs together, the programs "in fact exhibit stable growth rather than volatility." According to Mr. Bange, since 1986 the annual amounts for these programs, taken together, were $1,098,000; $2,143,000; $2,154,000; $2,400,000; and $2,453,000.

The Commission does not agree with OPC's position that the five programs should be considered individually to assess their respective volatility, but then viewed collectively to calculate a normalization adjustment for these programs. Instead, we find that the five programs, taken together, do not exhibit volatility so as to necessitate a normalization adjustment. We, therefore, reject OPC's proposed adjustment.

P. Rate Case Expense

OPC witness Gallagher recommends that the Commission normalize the Company's test year rate case expense since, during the test year, BG&E incurred significant expenses for portions of two major rate cases as well as its Fuel Rate

cases. In Mr. Gallagher's view, this level of rate case expense will not recur on a prospective basis. His proposed adjustment normalizes the test year amount ($757,000) based upon a four-year average ($222,000) over the years 1986-1989. During each of those years, rate case expenses relating to portions of only one base rate case are reflected on the Company's books.

Company witness Bange views such an adjustment as "inappropriate" in light of Mr. Brady's testimony anticipating another Company base rate filing in 1991, Mr. Gallagher's own recommendation of a new BG&E filing in 1991 to account for Brandon Shores Unit 2, a continuation of Fuel Rate proceedings involving the Company, and possible additional proceedings regarding the Susquehanna purchased capacity charges. Because such activity in 1991 will significantly exceed the Company's four-year average, Mr. Bange asserts that a level of expense at least equal to the test year level should be expected.

While a year with reduced adversarial regulatory proceedings involving BG&E would indeed be welcome, we do not anticipate such an occurrence. Instead, we anticipate additional proceedings, as well as extensive litigation concerning the Company's Fuel Rate and replacement power costs associated with the outages at Calvert Cliffs. In view of such proceedings, we reject OPC's proposed adjustment to normalize rate case expenses.

Q. Nuclear Operations and Maintenance Expenses

A major ratemaking issue in this proceeding is the total amount of expenditures which are necessary and proper for the operations and maintenance ("O&M") of BG&E's Calvert Cliffs Nuclear Power Plant ("Calvert Cliffs" or "CCNPP"). Specifically, the Commission must decide whether the nuclear-related O&M expenses during the test year should be accepted as representative of the prospective O&M costs for the rate-effective period. In this regard, we note that our review and findings will pertain to the reasonableness of the Company's test year O&M expenses for purposes of setting base rates. Issues regarding possible Company responsibility for replacement power costs associated with the outages at Calvert Cliffs will not be addressed. Those questions are the subject of an on-going, extensive investigation in Case No. 8520K, BG&E's Fuel Rate proceeding, in which many more facts will undoubtedly be presented. Accordingly, our decision in this base rate proceeding will have no res judicata effect in Case No. 8520K.

In December 1988, the Nuclear Regulatory Commission placed Calvert Cliffs on its "watch list," a designation resulting in closer monitoring and increased attention by the federal agency. As of the date of this Order, CCNPP continues to be on the NRC's watch list. In the spring of 1989, both Calvert Cliffs units were taken out of service for extended outages. Calvert Cliffs Unit 2, which was taken out

of service for problems related to the pressurizer heater sleeve, continues to be off line at this time. Currently, BG&E anticipates the unit will return to service in January 1991. Calvert Cliffs Unit 1, which was originally taken out of service in light of the heater sleeve problems at Unit 2, operated a total of 10 days during the test year. Unit 1 was returned to service on October 5, 1990, and is currently operating at full power.

Over the past three years, O&M expenditures at Calvert Cliffs have risen dramatically. Nuclear O&M for the calendar year 1988 amounted to $75 million, while actual O&M expenditures for the 12-month test year ended July 31, 1990 have risen to $142 million. BG&E maintains that the dramatic increase in O&M expenditures over the last three years is primarily due to the exacting requirements of the evolving nuclear regulatory environment. The Company urges the Commission to accept the test year level of O&M as reasonable for maintaining and operating CCNPP safely and efficiently during the rate-effective period.

In Case Nos. 8190 and 8208, the Company proposed adjustments to test year operating results in order to reflect, among other things, what BG&E termed "rising performance expectations" in the nuclear power industry. In our decisions, issued in late 1989, we accepted the test year level of expenditures for nuclear O&M but rejected the Company's proposed adjustments for projected increases. More

specifically, we found that the test year level of nuclear O&M expenses reflected programs and procedures incurred to assure safe operations at Calvert Cliffs. We also found, however, that the Company's proposed adjustments for projected increases in test year expenses had not been shown to be known and certain.[14]

As stated above, the Company proposes that the booked level of nuclear O&M for the 12 months ended July 1990 be utilized as the appropriate proxy for the rate-effective period. However, People's Counsel vigorously argues that the test year costs are not representative. Due to the prolonged outages at Calvert Cliffs, it is the position of People's Counsel that certain test year nuclear O&M costs were non-recurring, imprudently incurred, or questionable. Therefore, People's Counsel disputes the premise that the test year level of O&M costs were necessary and proper and should be relied upon for ratemaking purposes in this case.

In the Company's direct case, four witnesses testified to the reasonableness of the test year nuclear-related O&M expenditures. These witnesses discussed current activities at CCNPP which require a higher level of expenditures at the two units. Mr. Poindexter described a regulatory environment in which the NRC has imposed many new requirements and expectations with respect to plant equipment and operational safety.

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[14] Re Baltimore Gas & Elec. Co., 80 Md. PSC 496, 50_ (1989).

Mr. Creel testified that nuclear O&M test year expenses were reasonable and reflective of conditions that will exist in the rate-effective period. Mr. Vollmer's testimony addressed the necessity and adequacy of recent activities and improvements at CCNPP. Mr. Doughty compared the level of Calvert Cliffs' O&M expenditures to those at other nuclear plants and offered perspectives on the reasons for the increasing nuclear O&M expenses.

OPC challenges the test year level of nuclear O&M expenses, as well as certain deferred nuclear expenses, which the Company seeks to recover in rates. Based upon the testimony and evidence of its witnesses, Messrs. Kononetz and Hooper, OPC argues that: the test period nuclear O&M expenses are not representative of future costs; costs for certain hardware and procedural deficiencies represent unreasonably incurred costs; certain deferred nuclear expenditures were not reasonably incurred in the test year; and, management inefficiencies resulting from BG&E's need to address numerous concurrent activities caused unnecessary costs to be incurred.

Company witness Poindexter provided a general response to OPC's recommendation that a total of $31.1 million in test year nuclear O&M expenses be disallowed for ratemaking purposes. Mr. Poindexter stated that the testimony of OPC's witnesses does not address the issue of what level of O&M expenses is necessary to operate Calvert Cliffs during the rate-effective period. The witness observed that the Company

spent $142 million on nuclear O&M during the test year and expects to spend more during the rate-effective period. While he acknowledged that certain specific maintenance costs at Calvert Cliffs will decrease by $13 million from the test year to the rate-effective period, he asserted that other itemized Nuclear Energy Division costs will increase by $19 million so that the overall level of nuclear O&M will increase. More specific responses to OPC's recommended individual disallowances were provided by Company witnesses Vollmer, Doughty and Marmaroff, as discussed below.

1. Non-Representative Costs/Non-Recurring Costs

The first disallowance proposed by People's Counsel is based upon the argument that test year O&M expenses are not representative of expenses which will be incurred during the rate-effective period. Because Calvert Cliffs Units 1 and 2 were off line for virtually all of the test year, OPC contends that BG&E accelerated more than 5,000 plant maintenance and modification activities into the test period. OPC asserts that these accelerated costs should be spread over at least a five-year period, to be "representative of the time that these activities would have occurred had the units operated as expected." As support for this view, Messrs. Kononetz and Hooper quote the testimony of a BG&E witness in the Company's current Fuel Rate case, Case No. 8520K, that, "the prolonged

duration associated with the pressurizer resolution presented BG&E with an opportunity to pursue other significant maintenance and modification activities . . . ." The Company witness in that case added that had these activities not been pursued during the outage, it would have been necessary to address them in future planned maintenance outages.

Two different methods were used by OPC witnesses Kononetz and Hooper to quantify what they believe was the level of non-representative nuclear O&M expenditures during the test year. The first method compared the March 1989 contractor staffing level (used as a baseline for the typical monthly contractor staffing levels during a representative test year) to the level of contractor staffing during the test year. According to OPC, the results of this method indicate that $23.995 million in accelerated maintenance O&M costs were incurred during the prolonged duration of the outages. The second method compared BG&E's 1989 forecast for nuclear O&M costs during 1989, increased by 10 percent, with the actual test year costs. This method indicated that test year nuclear O&M costs increased by $29.143 million over the Company's own forecast. In order to give BG&E "the benefit of the doubt," Messrs. Kononetz and Hooper recommend using the lower figure to reflect the "non-representative" nuclear O&M expenses during the test year. Since, in their opinion, these costs would normally have been incurred over a five-year period, they

recommend that only one-fifth of the $23.995 million be included in test year operating expenses. In its Reply Brief, OPC suggests that the remaining portion be amortized.

In rebuttal testimony, Company witnesses Doughty and Marmaroff suggest that OPC witnesses Kononetz and Hooper do not understand the use of Maintenance Orders ("MOs") at CCNPP and therefore have misconstrued the significance of the completion of more than 5,000 maintenance items during the test year. They testified that the total 1990 MO trend is consistent with the historical total of 17,000 new MOs generated in each of the preceding three years. This consistency leads them to conclude that 1989/1990 was not a period with an abnormally large number of MOs. They also concur with testimony offered by BG&E witnesses Poindexter and Creel that the overall level of O&M expenditures for the test year is indicative of expenses expected during the rate-effective period. Finally, Messrs. Doughty and Marmaroff fault OPC's methods for quantifying the alleged accelerated maintenance activities.

BG&E's witnesses contend that the rate setting adjustments advocated by OPC ignore the fundamental nature of maintenance expenditures; i.e., maintenance is by its nature partially non-recurring. It is their position that no one should expect that the exact same maintenance projects and activities which occurred in the test year will be performed in the rate-effective period. According to BG&E, some maintenance activities can be expected to be unique and non-recurring as

specific components of the complex nuclear systems at CCNPP are maintained or specific problems are investigated. The Company argues that, when the Commission reviews these maintenance expenditures, the appropriate question is whether the aggregate amount of these expenses is a reasonable reflection of the expense level likely to occur during the rate-effective period. In this regard, BG&E witnesses testified that despite the projects which were accelerated into the test year, a significant backlog of lower-priority maintenance items remains.

Moreover, as a result of opening many systems during the extensive outages at CCNPP, the Company has identified various operations and maintenance activities which it asserts will cause O&M expenses to continue to be equal to, and probably rise above, test year levels. Company witness Poindexter identified specific items which would account for approximately $19 million of increased O&M costs. Such costs include staffing the Electrical and Controls Unit, a sixth shift of operators, as well as general improvements to planning and scheduling activities. In addition, O&M costs will increase in order to fulfill BG&E commitments for improvements in Electrical Systems Distribution, Reliability Engineering, Quality Verification Section and additions of administrative support in the Procurement Engineering Unit and the Contract Administration Unit.

Having considered this issue, we conclude that the Company's overall level of test year nuclear O&M expenses is reasonably representative of expenses which will be incurred

during the rate-effective period. Except for the pressurizer heater sleeve activities, discussed below, we believe that test year maintenance projects will be replaced by other operations and maintenance activities necessary in the course of operating and maintaining CCNPP during 1991. We are persuaded that a reduction in O&M expenditures during the rate-effective period of the magnitude suggested by OPC will not occur.

In our opinion, acceptance of the ratemaking adjustment suggested by OPC would result in an unrealistic and insufficient nuclear O&M expense level. As we noted in our decision in Case No. 8208, "the NRC is charged with the design and administration of programs to insure the safety of the operation at Calvert Cliffs . . . [while] the Commission has a concomitant responsibility to insure that the Company is provided with the funds necessary to implement these vital programs on a reasonable basis."[15] Therefore, we will not adopt OPC's proposed adjustment to amortize expenditures associated with accelerated O&M projects and activities.

In addition to the accelerated maintenance costs which it believes are non-representative of the test year, OPC contends that certain test year costs associated with testing, examining and removing CCNPP's pressurizer heater sleeves will not recur in future years. As a result, OPC argues that the pressurizer investigation expenses, totaling $5.227 million,

[15] Baltimore Gas & Electric Co., 80 Md. PSC 496, 507 (1989).

should not be considered normal test year expenditures. On Brief, OPC suggests that the Commission amortize this amount as an extraordinary expense over the life of the plant, and capitalize the unamortized portion, citing Re Baltimore Gas & Elec. Co., 71 Md. PSC 249, 262 (1980).

With respect to this issue, Company witnesses Doughty and Marmaroff agree that the analysis and testing associated with the heater sleeve problem is "non-recurring" in terms of the specific work performed.[16] However, they do not agree that such costs should be excluded from test year expenses. They argue that while the particular activities may be non-recurring with reference to specific hardware, it is expected that over a period of time, there will be a similar level of O&M activity required at Calvert Cliffs.

In contrast to those maintenance costs which OPC argues are non-representative, the costs associated with investigating problems with CCNPP's pressurizer heater sleeves are, indeed, a substantial one-time expenditure. As such, we consider these costs to be an "extraordinary maintenance expense" which should be amortized over the life of the plant, with the unamortized portion included in rate base. This treatment is consistent with our decision in Re Baltimore Gas

[16] The actual physical repair work has been capitalized and is not a part of this O&M adjustment.

and Elec. Company, 71 Md. PSC 249, 262 (1980). Accordingly, we will increase test year rate base by $2.543 million and increase net operating income by $3.319 million.

2. Costs for Certain Hardware and Procedural Deficiencies

a. Abnormal Operating Procedure-9

In the event of a control room fire, nuclear plant licensees must be able to bring the plant to a safe shutdown from a remote location. The written procedures to accomplish this at Calvert Cliffs are known as AOP-9. In early 1989, BG&E initiated a programmatic overview of certain NRC requirements, including the AOP-9 for Calvert Cliffs. Following a May 1989 "walk-through" of the AOP-9 procedure, the Company filed a 10-page Licensee Event Report ("LER") with the NRC which concluded that, "there may not be adequate assurance that we could concurrently bring both units to a cold shutdown condition in accordance with Appendix R requirements . . . ." BG&E further determined that, "the condition of AOP-9 constituted a nuclear safety issue' and that this condition was reportable to the NRC.

The LER also identified several technical deficiencies with the AOP-9 including, "missing information, incorrect information, steps not prioritized as a result of not having an adequate technical basis, and inadequate references to other procedures and requirements." Another concern was inadequate

staffing to implement AOP-9. The LER noted that the last revision to AOP-9 for Unit 1 was completed in September 1984, and in April 1986, for Unit 2.

According to the LER, the "root cause" of the inadequacies of the AOP-9 was "the failure to perform an adequate, dual unit validation and verification of AOP-9." Contributing causes included: the AOP-9 had not been revised to reflect the current industry practice of using safety function parameters and time lines when developing Alternate Safe Shutdown procedures; a worst-case simultaneous two-unit walk-through of the procedure had not been performed; and, adequate resources had not been assigned to ensure the Appendix R compliance program was maintained consistent with current commitments and industry guidance.

In order to correct the deficiencies identified in the walk-through of the AOP-9, BG&E determined that a current technical basis document for AOP-9 should be developed and staff levels augmented as necessary. It was also recognized that training for the revised AOP-9 would be necessary. Further, in light of the problems with its AOP-9, the Company concluded that an evaluation of other Abnormal Operating Procedures at CCNPP should be conducted in order to ensure that all such procedures had adequate technical bases.

OPC argues that costs related to the AOP-9 were imprudently incurred and, therefore, should be removed from test year expenditures. More particularly, Messrs. Kononetz

and Hooper testified that: costs associated with the evaluation and correction of BG&E's AOP-9 and other Abnormal Operation Procedures would not have been necessary had they been properly formulated initially; re-training to the new AOP-9 revision would not have been necessary; certain of the design modifications could have been more efficiently implemented earlier and at a resulting lower cost; and procedure revisions required to be performed by personnel associated with the Configuration Management and PUP efforts could have been more efficiently implemented earlier and at less cost. However, OPC's witnesses also note that AOP-9 corrective action costs are included in various O&M expense categories as well as in the Configuration Management and Procedure Upgrade Program deferred expense categories. As a result, they were unable to identify and quantify the associated costs for their recommended disallowance.

On rebuttal, BG&E witness Vollmer disputed Messrs. Kononetz and Hooper's assertions that the costs for corrective actions related to AOP-9 were not reasonable, necessary, and proper. On the contrary, he testified that all AOPs are reviewed on a periodic basis and that such costs are ordinary and necessary O&M costs. Nor did he believe that design modifications could have been more efficiently implemented earlier and at less cost. He further asserted that "isolated problems and deficiencies will occur." Because the configuration management program found, reported, analyzed, and

corrected the problems associated with the AOP-9, Mr. Vollmer believed that no mismanagement occurred, and that no disallowance is warranted.

In a similar vein, BG&E witnesses Doughty and Marmaroff testified that OPC's witnesses "provided no basis for their conclusions, used hindsight, and applied a standard of perfection." They also noted that some of these costs are recommended by OPC for disallowance in other categories, so that there was a potential for double counting.

On Brief, BG&E objects to the use by OPC's witnesses of the AOP-9 Licensee Event Report, calling it a document "written in hindsight, after a deficiency has been identified, to describe the sequence of events, identify root causes and describe corrective actions." The Company also objects to citations by Messrs. Kononetz and Hooper to that portion of the LER describing Company actions from 1984 through 1989.

At the outset, we reject BG&E's position regarding use of its Licensee Event Report to the NRC. The Commission believes it entirely appropriate to utilize the Company's own analysis, as set forth in its LER, to review and evaluate whether its actions in a given situation or over a given period of time were reasonable. Clearly, an evaluation of this type must look backward; however, the Company's assessment, as set forth in its LER, was presented in t[illegible] which recognized the obvious shortcomings in its own performance.

As we have done in other situations, we evaluate whether a company's actions were proper under the circumstances and knowledge at the time. With respect to the AOP-9, we conclude that the Company's actions were deficient. BG&E's own analysis shows that from 1984 for Unit 1, and from 1986 for Unit 2, the Company failed to adequately review the NRC's Appendix R procedures to ensure that, for example, the AOP-9 could actually meet NRC requirements. Both the root cause and contributing causes of the AOP-9 inadequacies cited in the LER clearly indicate management inattention to a procedure which has safety implications for the operation of Calvert Cliffs. As a result, we find that the costs associated with curing the defective AOP-9 were avoidable and, therefore do not constitute proper expenses for the purpose of setting rates in this case.

BG&E did not provide an estimate of the costs associated with the AOP-9 activities during the test year. In the absence of a cost figure from BG&E, which bears the burden of proof, we will increase test year net operating income by $400,000, an amount which should cover the actual expenditures for curing the AOP-9 deficiencies.

b. Electrical Cable Separation

The NRC's electrical cable installation and separation requirements are implemented at Calvert Cliffs in "Design and Construction Standards for Cable and Raceway" E406. Cable separation is required to assure that a single failure or event could not impact more than one train of safety equipment.

The procedure requires that each of six cable separation groups be physically separated from one another horizontally (three feet minimum) and vertically (five feet minimum) or by an intervening barrier.

Following an NRC inspection conducted from November 1989 through December 1989, the NRC issued BG&E a Notice of Violation which, among other things, identified five examples of inadequate cable separation at Calvert Cliffs. According to the NRC Notice of Violation, "the first two deficiencies appear to be original construction while the last two are apparent modifications. These deficiencies, together with the damaged and uncorrected barrier, are indicative of a programmatic weakness in the assurance of adequate separation of safety related cable." The cost to BG&E to correct the nonconforming conditions was $887,000.

OPC contends that because of deficiencies in Calvert Cliffs' design and construction documents, the costs associated with inspecting and correcting electrical cable separations at CCNPP were avoidable and should not be recovered from ratepayers. According to Messrs. Kononetz and Hooper, the "base document" used for BG&E's cable installations "was not consistent with other documents identifying BG&E's compliance with regulatory requirements." While acknowledging that these types of mistakes will occur, Mr. Kononetz stated that the Commission should consider the lack of timeliness in identifying the problem. He added that these deficiencies should have been discovered through the quality assurance and

quality control process in the construction and subsequent modification of Calvert Cliffs. Because they were not, Messrs. Kononetz and Hooper believe that the associated costs were imprudently incurred during the test year.

Company witnesses Doughty and Marmaroff countered that OPC used hindsight in making its evaluation; a standard of perfection was applied; some of the work was for the installation of fire barriers, which had not been previously installed and were found to be necessary; and, some of the incurred costs were not directly related to any claimed deficiency in CCNPP's original design or construction documents. They also testified that a Tenera Engineering Services report to BG&E noted that the CCNPP criteria was typical of the separation criteria for many plants of its vintage. Finally, they asserted that the NRC had applied a changed and higher standard in evaluating CCNPP's electrical cable separation.

Similarly, BG&E witness Vollmer testified that nuclear plants constructed prior to 1980 "did not develop and maintain detailed design criteria and did not install cable with the QC [quality control] checks and overall attention to detail that more current plants were subjected to . . . ." He added that "such deviations are expected given the nature of ongoing repairs and modifications in a complex facility." Mr. Vollmer asserted that while deficiencies are to be avoided, inspection and corrective actions relating to cable separation should be considered a normal and routine O&M cost.

While it is true that the nature and extent of the Company's response to Calvert Cliffs' nonconforming electrical cable separation was appropriate, that does not mean that the costs associated therewith are necessary and proper. Although BG&E witnesses allege that changed requirements resulted in the NRC finding deficiencies in CCNPP's electrical cable separation, they do not show that any such changes allow electrical cables to be closer than three feet horizontally or five feet vertically. Instead, we find that CCNPP's original documents were faulty, that the deficiencies should have been discovered at a much earlier point in time, and that today's rates should not reflect the costs associated with curing these longstanding defects. We will accept OPC's adjustment and increase test year net operating income by $887,000.

c. Motor Operated Valves

As a result of a 1985 incident at another nuclear power plant, the NRC issued IE Bulletin 85-03 which promulgated requirements to assure the operational readiness of motor operated valves ("MOV") in a plant's high pressure coolant injection, core spray, and emergency feedwater systems. By letter dated May 15, 1986, BG&E advised the NRC that it had completed the first of the Bulletin's five requirements; the Company also committed to complete the remaining requirements of the Bulletin by July 1, 1987.

On May 1 through May 5, 1989, the NRC performed an inspection to review the Company's actions in response to IE Bulletin 85-03. The inspection also reviewed BG&E's "engineering and maintenance activities to assure the operational readiness of the motor operated valves." Following the NRC inspection, a Notice of Violation was issued. In the June 16, 1989 letter transmitting the Notice, the NRC states that "it is important that proper management attention be given to the MOV maintenance program deficiencies identified in this report."

According to the Notice of Violacion, contrary to BG&E Technical Specifications and NRC requirements, the Company had no procedures for conducting the following maintenance activities that could affect the performance of safety-related equipment:

> (1) No procedural requirements exist for safety related MOV actuators to specify the frequency of inspections or the necessary criteria for stem lubrication of the actuators to assure proper operation. The inspector identified [three MOVs] with unlubricated valve stem
>
> (2) Criteria were not specified to establish safety related MOV limit switch and bypass switch settings for proper MOV operation.

During a review of CCNPP's test records, the NRC inspector noted that several MOVs in Unit 1 exhibited potential lubrication degradation of grease and the use of different

grease. Records for Unit 2 showed discoloration of grease, an indication of potential grease degradation; 10 of 12 Bulletin valves exhibited similar lubrication deficiencies.

The Notice of Violation concludes that BG&E had not addressed all of the significant aspects of the NRC's IE Bulletin 85-03. It also identified deficiencies in a torque switch setting and in the maintenance (lubrication) of MOVs.

Introduced into evidence by OPC was a Company document entitled "Estimate of Expenditures" which set forth the estimated cost to replace 62 torque switches in Limitorque Motor Operators and to overhaul 90 MOVs. The document notes that the "failure of approximately eighty percent of motor operator grease samples or internal parts expanded the scope [of this project]." According to a second Company document, the original project was designed to replace 62 torque switches (upon the advice of the manufacturer) at an estimated cost of $85,000. The revised project called for the replacement of the torque switches and a complete overhaul of 90 valves, at a total additional cost of $1,415,000.

Citing the NRC documents, OPC witnesses Kononetz and Hooper contend that because the increased MOV work was necessitated by deficiencies in BG&E's procedures and maintenance practices, the additional costs to overhaul the 90 MOVs was avoidable. OPC argues that the Company's flawed lubrication procedures were the direct cause for the need to overhaul 90 MOVs and that ratepayers should not be required to pay for the Company's imprudence.

In rebuttal, Company witness Vollmer asserted that NRC Generic Letters and Supplements to IE Bulletin 85-03 indicate an evolving regulatory environment with respect to MOVs. He also states that as a result of efforts by other licensees to comply with IE Bulletin 85-03, the NRC's scope of review and licensees' MOV programs were expanded. He considers the costs to meet these expanded requirements to be routine and unavoidable.

Also on this issue, Messrs. Doughty and Marmaroff contend that OPC has incorrectly linked the deficiencies in maintenance activities identified in the NRC Notice of Violation with the BG&E Revised Estimate of Expenditures for overhauling the MOVs. The witnesses assert that the valves were overhauled after the Company's own maintenance activities indicated that the MOVs had "worn or deteriorated components which required repair." They further state that only a portion of the actual costs for the accomplishment of MOV maintenance work was incurred during the test year.

Having considered the evidence, we conclude that there were not adequate procedures for lubrication of MOVs which are necessary for the safe operation of a nuclear power plant. The Company has not provided evidence that the overhaul of 90 MOVs was required by normal wear and tear rather than by the absence of adequate procedures to ensure that the MOVs were properly lubricated. While BG&E refers

to generic problems and changing regulatory requirements, the implications of the NRC Notice of Violation are clear: the Company's MOV maintenance program was deficient. Although BG&E alleges that the costs identified by OPC are overstated, the Company did not provide an estimate of the specific costs. Accordingly, we will accept OPC's adjustment for this item.

d. Low Temperature Overpressure Protection

By letter dated March 6, 1990, the Company was advised by the NRC that a Notice of Violation and Proposed Imposition of Civil Penalty was being issued. The Company was found to be in violation of NRC requirements after a special, unannounced safety inspection reviewed the Low Temperature Overpressure Protection Plan ("LTOP") at CCNPP. The purpose of the LTOP is to "prohibit the reactor pressure from exceeding certain design limits during low Reactor Coolant System temperature conditions so as to protect the reactor vessel from brittle fracture."

According to the March 6 letter, the Operating License issued for Calvert Cliffs Unit 2 in 1976 was conditioned upon the Company developing an NRC-approved LTOP plan. The plan submitted by the Company in 1977 included 38 commitments concerning administrative controls, hardware improvements, technical specification changes and operator training. The plan was approved by the NRC in August 1978.

The NRC's March 6 letter goes on to observe that on three separate occasions between 1987 and 1989, "information

was provided to, or developed by [BG&E's] staff . . . which, if properly evaluated, should have resulted in recognition that some of the original commitments had not been implemented." More specifically, "procedures had not been developed to prohibit either the testing of the emergency core cooling system with the plant solid, or the startup of the shutdown cooling system when steam generator temperatures were above 220 degrees F."

The NRC also found that in March 1987 and again in September 1989, a thermohydraulic reanalysis of the LTOP system was performed by the Company in response to an NRC Generic letter. The reanalysis indicated that the Company's' LTOP system,

> was potentially inadequate . . . . However, no further evaluations were made, nor corrective actions undertaken . . . . If adequate evaluations had been performed, the failure to meet all of your original LTOP commitments would have been identified. These failures to identify and correct a significant condition adverse to quality constitute a violation of NRC requirements.

As a result of these findings, the NRC issued a civil penalty for violations of NRC requirements. The base civil penalty of $50,000 was escalated by 100 percent,

1

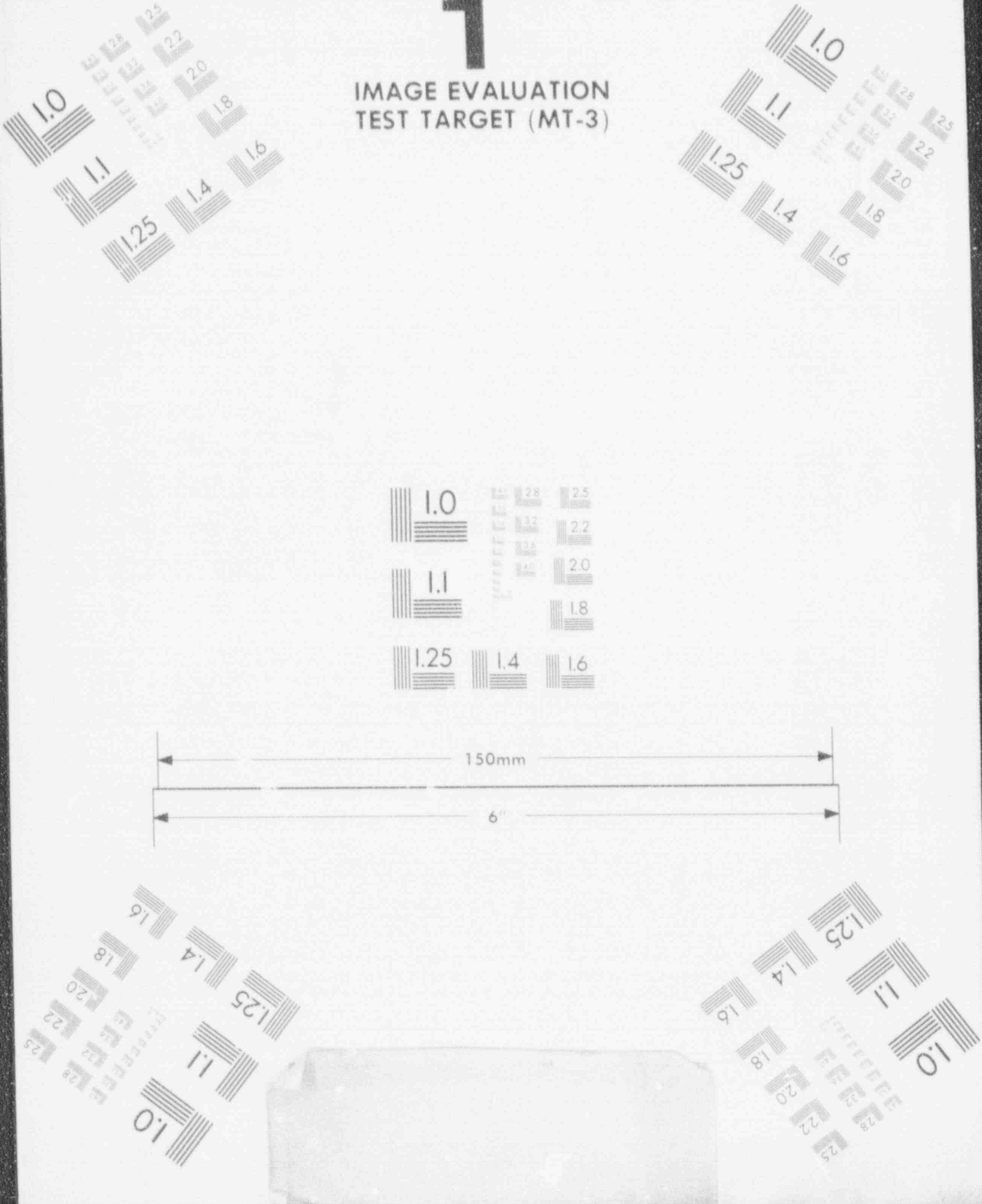
IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION
TEST TARGET (MT-3)



1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

> because the violation was identified by the NRC and should reasonably have been identified sooner if adequate management control of work activities had been in place. Your corrective actions . . . were neither prompt nor comprehensive, and therefore, 50% escalation of the base civil penalty on this factor is warranted.

Based upon the NRC documents which were introduced into evidence, OPC argues that the costs associated with correcting the LTOP deficiencies should not be borne by ratepayers. OPC further maintains that none of the alleged changes in NRC requirements had any impact upon the Company's LTOP problems. Although requested by OPC, the Company was unable to provide an estimate of the costs associated with correcting the LTOP deficiencies.

In response to this issue, the Company's witnesses try to explain BG&E's actions by referring to changing regulatory expectations and requirements. Mr. Vollmer states that BG&E's activities in 1989 and 1990 in response to the NRC's changing LTOP requirements were "prompt and effective." Thus, costs associated with the LTOP review should be considered a normal and routine cost. Similarly, Messrs. Doughty and Marmaroff assert that LTOP "is an example of a generic industry problem." They also testified that BG&E's responses were "thorough and timely, and the associated costs reasonable and necessary." The witnesses conclude by saying, "[w]hether these work activities were implemented in the test year or in prior years, they are appropriate for inclusion as recoverable nuclear O&M costs."

Based upon the record evidence, the Commission concludes that BG&E failed to fulfill certain of its LTOP commitments to the NRC and failed to implement timely corrective action regarding its LTOP. The NRC documents which describe the LTOP deficiencies clearly indicate safety-related problems extending over a period of several years. For example, commitments made in 1977 had never been implemented. Also, NRC inspections in 1987, 1988, and 1989 indicated unresolved problems. As we found with respect to the MOVs, the Company's references to a changed regulatory environment and generic industry problems were not supported by the introduction of NRC documents into evidence. Thus, we are unable to determine for ourselves the relevance, if any, of the documents alluded to by Company witnesses. Moreover, even if it is assumed that the LTOP costs would otherwise be recoverable, the record indicates that they should have been incurred at an earlier point in time and not during the test year. Accordingly such costs will be excluded from the test year O&M expenses.

The Company states that it is unable to provide an estimate of the costs associated with the LTOP deficiencies. In the absence of a cost figure from BG&E, which bears the burden of proof, we will increase test year net operating income by $600,000, an amount which should cover the actual amount expended by BG&E during the test year to cure the LTOP deficiencies.

3. Questionable Costs

OPC recommends that the test year O&M costs be adjusted by removing certain "questionable costs" which "appear to have been imprudently incurred." Costs which have been designated as questionable by OPC include two test year expenses and four deferred nuclear expenditures. The test year expenses are associated with the Procedure Upgrade Program ("PUP") and the Nuclear Information Project ("NIP"). The four deferred nuclear expenditures include the following foundational projects which were capitalized and amortized pursuant to the Commission's decision in Case No. 8208: Procedure Upgrade Program; Configuration Management; Procurement; and, Nuclear Information Project.[17]

OPC's witnesses Kononetz and Hooper testified that certain of the costs incurred for these activities including, but not limited to, those associated with BG&E's Restart Commitments should not have been incurred. The witnesses stated that BG&E management was unreasonable in not causing proper actions or corrective actions to have been implemented earlier, as a routine matter in plant management, operations, maintenance and outage activities. In their opinion, many, if not all, of BG&E's Restart Commitments comprise unreasonably-incurred costs; the O&M expense and deferred cost components associated with those Restart Commitments should not be

[17] Re Baltimore Gas & Electric Co., 80 Md. PSC 496, 508 (1989).

considered as necessary and proper. OPC further argues that other PIP costs have not been fully investigated and determined to have been reasonably incurred, at this time. Thus, they recommended that any final determinations about these matters be deferred until BG&E's fuel rate proceeding, Case No. 8520K.

BG&E's witnesses take issue with the analyses and recommendation offered by OPC's witnesses. Messrs. Doughty and Marmaroff challenge the link drawn by Kononetz and Hooper between the work associated with the Restart Commitment and elements of the Performance Improvement Plan. Mr. Vollmer states that the PUP activities were not a belated response to NRC concerns. The costs associated with PUP activities, particularly for older plants where procedures need upgrading, are routine and normal in the nuclear industry and require a period of years to complete. In his opinion, there was no reason for BG&E to commence a programmatic effort to upgrade procedures at CCNPP prior to 1989. On Brief, BG&E argues that OPC's witnesses not only failed to provide any link between alleged mismanagement and any associated avoidable costs, they also failed to provide a reasonable basis for their cost quantification.

In Case No. 8208, based on the evidence in that proceeding, we determined that the foundational phases of four projects qualified for capitalized ratemaking treatment. In this case, People's Counsel again questions these costs. BG&E argues that the Company has provided additional evidence on the subject of reasonableness while the doubt raised by People's Counsel is not significantly different from the prior case.

In discussing the issue of deferred nuclear expenditures in Case No. 8208, the Commission found that the programs and procedures contained in the PIP "should have been instituted or would have been incurred in order to assure safe operations at the Calvert Cliffs units" and that the Company "met its burden in showing that test year O&M expenses were not incurred due to imprudence and are necessary and proper for the safe operation of the Calvert Cliffs units." The Commission further found that "the record does not support a finding that any delays in implementation of such programs substantially increased their cost, or that they could have been avoided." Reviewing the additional evidence on this subject in this proceeding, the Commission reaches the same conclusion. Therefore, we will not change the accounting status of these capitalized projects.

Also, we believe that the Company has adequately responded to the questions about PUP and NIP raised by witnesses Kononetz and Hooper. Our review of the record indicates that the O&M expenses for the Procedure Upgrade Program and the Nuclear Information Project are reasonable and appropriate for inclusion in the test year. Therefore, we will not accept OPC's proposed ratemaking adjustments with respect to these costs. As a closing observation, we note a substantial shortcoming to OPC's witness' suggestion that base rate matters be deferred for consideration in Case No. 8520K. At issue in that fuel rate proceeding are the reasonableness of

replacement power costs. In that connection, judgments may be made as to the avoidability of projects which may have prolonged outages. O&M expenditures, as such, will not be at issue and no determination on their reasonableness will be made.

4. Management Inefficiencies

The final nuclear O&M adjustment proposed by OPC is based upon a contention that being placed on the NRC's "watch list" was the direct cause of increased O&M costs at Calvert Cliffs. OPC refers to alleged "inefficiencies" by management which were the consequence of having to respond to "the numerous, significant concurrent activities at Calvert Cliffs during the test year." Examples cited by Messrs. Kononetz and Hooper of significant activities requiring management attention include, among others: formulation, staffing and implementation of BG&E's Performance Improvement Plan (PIP) and Procedure Upgrade Program (PUP); investigation and resolution of the pressurizer heater sleeve leakage problem; responding to the NRC's CAL and STI concerns; planning scheduling and implementation of accelerated maintenance activities; contracting with, and control of, exceptionally high levels of contractor services; and, planning and implementation of corrective action programs associated with the hardware and procedural deficiencies noted above.

After discussing these activities individually, Messrs. Kononetz and Hooper assert that BG&E was not able to exercise the necessary degree of control. They further fault the Company for not routinely keeping its procedures updated and in not ensuring compliance with existing procedures; the expenditures incurred during the test year to "catch up," are deemed by OPC to be unreasonable, unnecessary, and improper.

OPC witnesses Kononetz and Hooper attempt to quantify the alleged management inefficiencies for purposes of a disallowance by estimating that at least 10 percent of BG&E's workforce activities and at least five percent of its contractor workforce activities were impacted. Applying these percentages to the test year labor and contractor costs results in their recommended adjustment of $8.985 million as costs unreasonably incurred. They also note, however, that some of these alleged inefficient costs are included, in part, in other categories of proposed disallowances and, thus, should not be duplicated.

In responding to the general allegations of management inefficiencies, BG&E's witnesses Doughty and Marmaroff emphasize that witnesses Kononetz and Hooper did not identify the existence or extent of the inefficiencies. Nor did OPC's witnesses define the criteria being used as a basis for its inefficiency calculation. Furthermore, Messrs. Kononetz and Hooper did not offer any justification for the specific ten and five percent figures utilized in calculating the disallowance.

Finally, BG&E notes that the quantification of the proposed disallowance includes double counting of certain costs associated with other proposed disallowances.

The Company argues that at no time did OPC's witnesses acknowledge the steps taken by BG&E to control and manage activities at CCNPP. On the other hand, BG&E's witnesses testified to 11 specific actions by BG&E's management which illustrate "management effectiveness and enhanced controls." One of the principal examples OPC's witnesses used to illustrate lack of management control was the deliberate reduction in contractor levels in May of 1989. BG&E asserts that contractor levels and costs were reduced because BG&E's management was taking appropriate action to effectively plan and execute the evolving work program.

The Commission concludes that the test year adjustment proposed by Messrs. Kononetz and Hooper should not be accepted. OPC's witnesses have not established a sufficient factual basis to support their general allegations of management inefficiency. Also, they have not established a factual basis for their opinion that 10 percent of BG&E's own work force activities and five percent of contractor work force activities were impacted. On the basis of the record in this case, we find no fault with the general efficiency of the management of the O&M activities at CCNPP with respect to the test year. Accordingly, this ratemaking adjustment, as proposed by OPC, will not be adopted by the Commission.

R. Net Operating Income Findings

After making all of the appropriate adjustments to net operating income, the Commission finds that the adjusted net operating income for BG&E's electric operations for the 12-month period ending July 31, 1990, was $321,006,000.

V. RATE OF RETURN

In its filing, the Company requested that its currently authorized rate of return of 10.01 percent be continued. Company witness Brady testified that the 10.01 percent return, which was authorized by the Commission less than six months before the Company's current filing, continues to be reasonable and appropriate. Subsequent to the rate of return presentations of the other parties, the Company sponsored rebuttal testimony regarding the Company's cost of equity by Dr. Charles E. Olson, an economist and president of a consulting firm. While Dr. Olson's testimony supported a higher cost of equity than that implicit in BG&E's 10.01 return, the Company used his testimony as an indication that its requested return was reasonable.

The Commission Staff presented the testimony of Patricia Ferguson, whose cost of capital analysis for BG&E indicated that an overall rate of return in the range of 9.69 to 10.19 percent was reasonable. Her recommended point estimate is 9.94 percent. Ms. Ferguson, however, does not

recommend a change in BG&E's current return of 10.01 percent since it falls within her range for the Company's cost of capital.

OPC sponsored the testimony of Basil L. Copeland, Jr., an economist specializing in energy and utility economics. Mr. Copeland's rate of return analysis for the Company, as subsequently revised in his rebuttal, indicated an overall rate of return in the range of 9.63 percent to 9.73 percent, with a point estimate of 9.68 percent.

GSA witness Phillip R. Winter, a Chartered Financial Analyst, testified that, based upon his cost of capital study for BG&E, a 9.79 percent overall rate of return is appropriate.

At issue in this case is the appropriate capital structure for BG&E, as well as the cost rate for each of its four capital components. The parties' positions on these issues are discussed below.

A. Capital Structure

BG&E witness Brady testified that if the Commission elects to establish a new rate of return for the Company, that a long-term "target" capital structure should be used. Such a capital structure, he believes, preserves "an appropriate balance between debt and equity while ensuring timely access to the Capital markets at a reasonable cost." This target consists of the following capital ratios: 43.47 percent long-term debt; 43.06 percent equity; 11.37 percent preferred stock; and,

1.83 percent short-term debt. According to Mr. Brady, as a result of expansion of the Company's electric system, "pressure has been placed on the Company's earnings and measures of debt service coverage." Use of the Company's target capital structure would "ameliorate the deterioration in the Company's financial strength and flexibility."

Staff witness Ferguson recommended use of BG&E's actual capital structure as of December 31, 1989, adjusted to reflect changes "deemed reasonable" through December 31, 1990. The components of this capital structure are as follows: 43.45 percent long-term debt; 40.75 percent equity; 13.19 preferred stock; and, 2.61 percent short-term debt.

OPC witness Copeland bases his rate of return recommendation upon the Company's actual capital structure as of July 31, 1990, consisting of: 41.7 percent long-term debt; 41.2 percent equity; 12.8 percent preferred stock; and 4.3 percent short-term debt.

GSA witness Winter also recommends use of BG&E's utility segment's actual capital structure as of July 31, 1990. According to Mr. Winter, the Company's actual capital structure "is reasonably leveraged and is not unnecessarily costly to ratepayers."

In numerous Commission decisions we have expressed our preference for using "a company's actual capital structure or that structure projected to exist during the rate-effective

period absent clear evidence on the record that such a structure will be unnecessarily burdensome to ratepayers."[18] We also recognize that use of a hypothetical capital structure may be necessary when the debt/equity ratios become unduly risky or uneconomical.[19] In this case, we find that the capital structure proposed by Staff, which reflects BG&E's expected capital structure as of December 31, 1990, will fairly reflect the capital components of the Company during the rate-effective period, while balancing the needs of the Company and its ratepayers.

B. Cost of Equity

In accordance with previous Commissions decisions, each of the expert witnesses utilized the Discounted Cash Flow ("DCF") method in determining their respective cost of equity recommendations. The DCF formula calculates the cost of equity by adding the dividend yield plus the expected growth in dividends. The witnesses' individual judgment becomes a factor in their selection of a period of time over which to calculate dividend yields and in projecting the growth in a company's dividend rate. In view of these opportunities for individual judgment, the witnesses' respective DCF analyses produce different results as to the Company's cost of equity.

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18 Re Baltimore Gas & Electric Co., 74 Md. PSC 249, 277 (1983).

19 See, for example, Re Baltimore Gas & Electric Co., 80 Md. PSC 396, 402 (1989).

As previously noted, in response to the rate of return recommendations of other parties, Dr. Olson presented testimony regarding the Company's cost of equity. In his opinion, Staff's range for the cost of equity is within the zone of reasonableness, while OPC's and GSA's recommendations are below the Company's true cost of equity capital.

Based upon an updated DCF analysis from that which he presented in BG&E's previous rate case, Dr. Olson believes the Company's cost of equity is currently between 13.75 and 14.25 percent. The dividend yield of 7.6 percent was based upon a dividend rate of $2.10 and the average of the high and low stock prices for the period April 1990 through October 1990. Following a method used by the Federal Energy Regulatory Commission ("FERC"), a "yield adjustment factor" of 0.19 percent was added to the 7.6 percent dividend yield figure. The purpose of this adjustment "is to project dividends forward to the mid-point of the upcoming year, since it is forward dividends that are properly employed in the DCF model."

Dr. Olson's estimated dividend growth rate of 5.0 to 5.5 percent is based upon three sources of information available to the typical investor: past and current trends in growth in dividends, earnings, and book value; data on projected growth in earnings and dividends; and, analysis of retention, or internal growth. He notes that most historical growth rates for BG&E have been above that level and that growth rates

forecasted by security analysts are somewhat lower. In his view, investors expect long-term growth to be higher than near-term growth for BG&E.

As a check on his cost of equity recommendation for BG&E, Dr. Olson conducted a DCF analysis of the 6 electric and combination gas and electric companies (all with nuclear exposure) which he studied in the Company's last base rate case. According to his analysis, the range of the cost of equity for this group of comparable companies is between 12.55 percent and 13.07 percent, before reflecting flotation costs.

The Company's "bare bones" equity requirement should be increased, according to Dr. Olson, by 8 percent in order to reflect financing costs and to protect against down markets. When the 12.79 to 13.31 percent return requirement is increased by 8 percent, the cost of equity is in a range of 13.81 to 14.37 percent. Dr. Olson's recommended range for the Company's cost of equity is 13.75 to 14.25 percent.

Staff witness Ferguson's DCF analysis used a dividend yield component calculated by dividing BG&E's projected dividends by the six-month average of its high and low stock prices for the period March 1990 through August 1990. A six-month average will, in her view, better reflect current market information and adjust for the impact of "random economic events." In addition to her cost of equity study for BG&E, Ms. Ferguson also performed a DCF analysis for a group of seven

utilities which, in her opinion, have risks comparable to those of the Company. The expected dividend yield for BG&E is 7.73 percent, while the average expected dividend yield for the comparable group of companies is 7.75 percent.

Ms. Ferguson determined BG&E's expected dividend growth rate to be within a range of 4.25 percent to 5.25 percent while the range for the group of comparable companies is 4.0 percent to 5.0 percent. In projecting BG&E's future dividend growth rate, Ms. Ferguson assessed both historical and forecasted growth rates in earnings per share ("EPS") and dividends per share ("DPS") for both BG&E and the comparable group. Her calculations for the historical growth in EPS and DPS are based upon a Log-Linear regression to calculate the most recent five, seven, and ten-year growth rates from 1980 to 1989. Forecasted growth rates in EPS and DPS were based upon investor service agencies' assessments.

In order to take into consideration the costs of underwriting a stock issuance and the pressure of stock prices which may follow a new issuance, Staff has increased the Company's dividend yield by 5 percent. Combining the adjusted dividend yield with the expected dividend growth rate results in a range of cost rates for equity between 12.37 percent and 13.37 percent. The midpoint in Staff's range is 12.87 percent. With respect to the comparable group of companies, Staff's calculated range for equity is between 12.14 percent and 13.13 percent.

OPC witness Copeland cautioned that, in his opinion, a DCF cost of equity estimate for BG&E is inherently less reliable than the average of a large sample of electric utilities since the former would, in effect, be a sample of one. For his purposes, Mr. Copeland selected a group of 85 electric utilities, excluding those which currently pay no dividend or those which have supernormal expected dividend growth rates because they have only recently restored the payment of dividends.

Based upon data as reported by Value Line, Mr. Copeland analyzed the five-year historical and projected growth rates in EPS, DPS, and book values, as well as the percentage of retained earnings to common equity, and an estimate of price growth. Excluding the five-year historical growth rates, he then averaged the remaining growth rates and added the 26 week mid-range dividend yields (for the 26 weeks ending June 30, 1990) to develop individual estimates of the cost of equity for each of the 85 firms in his sample. Mr. Copeland believes it appropriate to discount or ignore evidence of BG&E's historical growth rates since the projected growth rates are all substantially lower than comparable historical figures. He also notes that other evidence presented by the Company indicates that BG&E is not likely to repeat its historical growth experience in the foreseeable future. According to Mr. Copeland, the average cost of equity for the 85 electric utilities was 10.7 percent.

Having expressed his reservations about performing a DCF analysis for a single company, Mr. Copeland calculated BG&E's cost of equity; his DCF analysis indicated a range between 11.5 percent and 12.0 percent. On rebuttal, based upon updated information, Mr. Copeland revised his estimation of the Company's cost of equity to be between 12.0 percent and 12.5 percent. He suggested an allowed return on equity for BG&E in the range of 12.25 percent to 12.5 percent, with the midpoint of 12.375 percent as his actual recommendation. His rate of return recommendation includes 10 basis points for flotation costs.

As a check on his DCF estimate of the Company's cost of equity, Mr. Copeland also did a "market risk premium" analysis which indicated BG&E's cost of equity is about 11.6 percent, and an "historical risk premium" analysis which indicated a cost of equity of 12.3 percent. Mr. Copeland believes these two analyses establish an upper limit of 11.6 percent to 12.3 percent to the range of reasonable estimates of the Company's cost of equity.

GSA witness Winter testified that, based upon his DCF analysis, capital cost trends, and returns available on equity investments similar to BG&E, the return on equity allowed the Company should be no greater than 12.5 percent. In his opinion, investors perceive BG&E's common stock as having an unusually low risk as indicated by a safety ranking and credit rating stronger than over 90 percent of the firms with which BG&E competes for capital.

The range of dividend yields used in Mr. Winter's DCF analysis (7.15 percent to 8.57 percent) was based upon the Company's monthly low and high stock prices for the three-month period July 1990 through September 1990, and its dividend payments during this same period. The data from this more recent period is considered by Mr. Winter to be a better indicator of BG&E's capital costs over the rate-effective period.

In order to determine the appropriate dividend growth rate for BG&E, Mr. Winter reviewed historical and prospective growth rates for the Company's dividends, earnings, book value, and stock price during the past five and ten-year holding periods as set forth in the June 22, 1990 Value Line Investment Survey. He also reviewed the near-term forecasts from IBES, Prudential-Bache, Value Line, and Salomon Brothers. Mr. Winter relied primarily upon long-term price and dividend growth histories and on investment firm forecasts for near-term dividend growth. He believes these factors should be "emphasized over earnings and book value growth, because price appreciation and dividend payments are the 'cash flows' actually received by investors and discounted in the DCF model." Mr. Winter places little reliance on BG&E's historical earnings and dividend growth rates "because they were recorded during a period of excessive earnings and are not generally expected over the near or long term."

Based upon his analysis, a 4 percent dividend growth rate can reasonably be expected for BG&E during the rate-effective period. Combining the 4 percent dividend growth rate with a dividend yield range of 7.15 percent to 8.57 percent results in a return on equity for BG&E in the range of 11.44 percent and 12.91 percent; his recommended point return is 12.5 percent. Mr. Winter observed that a 12.5 percent return on equity offers a risk premium of approximately 300 basis points over recent yields on BG&E's debt which, in his opinion, would be "somewhat generous for the rate-effective period."

Finally, Mr. Winter believes that since common equity issuances have both positive and negative effects on stockholders, which effects offset each other, no flotation adjustment is necessary.

While the evidence and testimony sponsored by BG&E, OPC and GSA has been useful in our decision regarding the Company's cost of equity, we note some weaknesses in methodology. For example, with respect to BG&E witness Olson's presentation, this Commission is not persuaded to adopt a "yield adjustment factor," even though such a factor is used by the Federal Energy Regulatory Commission. Similarly, an eight percent adjustment to account for flotation costs and market pressure seems excessive at this time. Further, we find that Dr. Olson's method of estimating the Company's dividend growth rate yields a result which overly emphasizes the high side of investors' expectations.

We also have reservations as to the usefulness of OPC witness Copeland's DCF analysis for electric utilities, many of which have no nuclear exposure. His risk premium and historical risk premia analyses appear to lack sufficient sensitivity to the special characteristics of individual companies, such as BG&E. Also, OPC's 10 basis points adjustment for flotation costs does not appear to be adequate.

GSA witness Winter used a three-month period for calculating BG&E's future dividend yields; the Commission believes that, in this case, a six-month period is a sounder approach. Mr. Winter's comparable earnings approach focuses upon an historical accounting of rate of return, rather than on investors' current expectations, as is preferred by the Commission. Also, GSA does not make any adjustment for flotation costs, costs which we believe should be reflected.

Instead we are persuaded by Staff's evidence that 12.87 percent is the appropriate cost of BG&E's common equity during the rate-effective period. In our opinion, Staff has properly applied the discounted cash flow methodology both to BG&E and to a comparable sample of companies. Staff's projected dividends for the Company are based upon a sound consideration of the current dividend, historical trends in dividend and earnings growth, and projections by Value Line. We also believe that, in this case, use of a six-month average of stock prices to determine a dividend yield is appropriate. Staff's method of adjusting the anticipated dividend yield by

five percent for flotation costs has been accepted in previous Commission cases. We note that Staff's DCF methodology produces a significant overlap between the range of the cost of common equity for BG&E and for the comparable sample of companies. For these reasons, we accept Staff's recommended cost of equity for BG&E of 12.87 percent.

C. Long-Term Debt

By recommending a continuation of its currently authorized 10.01 percent rate of return, the Company uses 7.78 percent as its embedded cost for long-term debt. Company witness Brady testified, however, that if a new rate of return is established by the Commission, the Company's target capital structure and different cost rates for capital components should be used.

The embedded cost rate used by Staff for the Company's long-term debt is 7.96 percent, which is the embedded cost projected for December 31, 1990. According to Staff, this cost rate reflects the Company's newly acquired $150 million revolving credit agreement and an expected $150 million long-term debt issuance.

In accordance with his recommendation that the Commission adopt the Company's actual capital structure as of July 31, 1990, OPC witness Copeland uses the Company's embedded cost of debt of 7.76 percent on that date.

GSA witness Winter recommends using the Company's July 31, 1990 embedded cost of long-term debt, adjusted to reflect projected financing requirements (at anticipated market rates) during the rate-effective period. His adjustment increases the actual embedded cost rate for long-term debt from 7.76 percent to 7.97 percent.

Having considered the evidence, we accept Staff's recommendation which recognizes the Company's embedded cost rate for long-term debt as of December 31, 1990 (the beginning of the rate-effective period) as well as specific known changes which will occur during the rate-effective period.

D. Short-term Debt

As with long-term debt, the Company argues that if a new rate of return is established by the Commission, the Company's target capital structure and different cost rates for capital components should be used. However, the cost rate for short-term debt implicit in the Company's return request is 9.0 percent. Both OPC witness Copeland and GSA witness Winter indicated that the July 31, 1990 cost of short-term debt of 8.45 percent continues to be appropriate. Staff witness Ferguson testified that a cost rate of 8.33 percent, which considers projections for 90-day commercial paper rates for 1990 and 1991, was appropriate. Consistent with our desire to

reflect the cost of capital during the rate-effective period, we will adopt Ms. Ferguson's recommendation of 8.33 percent as the cost rate for the Company's short-term debt.

E. Preferred Stock

The cost rate for preferred stock included in the Company's rate of return request is 7.51 percent. OPC's witness Copeland utilizes the 7.53 cost rate as of July 31, 1990. GSA witness Winter recommends a cost rate of 7.53 percent, which reflects the redemption of two 12 percent preference stock issuances during the rate-effective period to be replaced with an issuance of preferred stock at 8.5 percent. The latter figure is primarily based on recent yields on the Company's debt and on the fact that preferred stock yields are typically 50 to 200 basis points below those required on a company's debt.

Staff witness Ferguson utilized a cost rate of 7.74 percent, based upon applying an 8.73 percent embedded cost rate to BG&E's preference stock issuance on June 7, 1990 of $65 million, and to an expected issuance of $35 million during the rate-effective year.

The Commission will again accept Staff's cost rate since it better reflects specific changes during the rate-effective period.

F. Overall Rate of Return

Applying the cost rates found reasonable herein to the capital structure previously found appropriate results in an overall cost of capital for BG&E of 9.94 percent, calculated as follows:

	Capitalization Ratio	Cost Rate	Weighted Cost
Long-Term Debt	43.45%	7.96%	3.46%
Short-Term Debt	2.61%	8.33%	.22%
Preferred Stock	13.19%	7.74%	1.02%
Common Equity	40.75%	12.87%	5.24%
	100.00%		9.94%

VI. REVENUE REQUIREMENT

Application of the 9.94 percent rate of return to the average electric rate base of $3,729,236,000 results in a net electric operating income requirement of $370,686,000. When adjusted test year net operating income of $321,006,000 is subtracted from this amount, the result is a deficiency in net operating income of $49,680,000, which, in terms of gross annual electric revenues, becomes $76,964,000.

VII. RATE DESIGN

BG&E offers a number of adjustments to its cost of service study and proposes various changes in rate design. Unless specifically rejected in the discussion that follows, we accept the adjustments and proposals of BG&E.

A. BG&E's Apportionment of Revenues Among the Classes

Mr. Hargest described BG&E's method of apportioning a rate increase among the customer classes. He sponsored two sets of rate schedules to reflect the Company's phase-in proposal. The requested revenue increase from both phases ($249.5 million) is apportioned among the classes to move each class' embedded rate of return closer to a 7 percent band around the system rate of return ("ROR"). This is done in three steps.

First, each class outside of the 7 percent band, whether above or below, is apportioned an amount that brings the class to the band. Each class within the band is apportioned only that amount necessary to maintain its position relative to the system ROR. In the second step, the remaining amount of the increase is apportioned among the classes in relation to test year base revenues, adjusted to include amounts determined in the first step. Lastly, revenues are separated between phase one and two rates.[20]

[20] Mr. Hargest testified that, even if the Commission rejects the Company's phase-in proposal, revenues can be apportioned in the same general way.

BG&E made two exceptions to this three-step procedure. The first exception is Schedule ES, which was given the same percentage increase as Schedule R. The other exception is Beth Steel. Its contract with BG&E requires that it receive the same percentage increase as Schedule P, the tariff for other industrial customers.

BG&E uses a fully allocated embedded cost of service ("COS") study for the 12 months ended December 1989 to derive the class rates of return. As a part of that study, BG&E employs the 4 CP Min/Max method to allocate production plant. The only novel adjustment to the 1989 study is the recognition of the cost of BSU-2.

The results of the COS study determine the apportionment of the rate increase among the customer classes. Seemingly, the returns from two classes are not close to a system average level, and the contributions from three other classes are too high. Stated another way, the study shows that: the returns from schedules R and ES are below the 7 percent band; schedules G, GL and Beth Steel are above it; and all other classes fall within the range.

After apportioning the revenues among the classes, Mr. Hargest made some further adjustments before designing the rates for individual customer classes. One such adjustment rolls the purchased capacity surcharge into base rates. Another adjustment pro-forms load management credit costs to

the rate-effective period. Finally, Mr. Hargest adjusted test year billing determinants to recognize Schedule G to GL conversions.

B. <u>BG&E's Intraclass Rate Design</u>

Mr. Hargest sponsored a marginal cost study, and explained the Company's approach in designing rates for each of the customer classes. BG&E's objective, he said, is to set intra-class demand and energy rate levels as closely as possible to reflect marginal costs. Of course, this approach is subject to the constraint of an embedded revenue requirement.

In contrast, customer charges are set generally to "match the estimated average monthly customer costs" that are shown in the 1989 COS study. However, an exception was made for two residential classes to avoid an "inordinate increase" in the customer charge. Specifically, for schedules R and ES, the proposed customer charge merely "reduces the gap" between the existing charge and the estimated cost by 50 percent.

The revenue increase to each class is first used to adjust customer charges. The remaining revenues are allocated in a two-step, 80/20 procedure. The first step assigns 80 percent of the remaining revenue on an equal percentage basis to each rate element. The final 20 percent is assigned to specific rate elements where current rates are less than marginal costs.

BG&E proposes just one change in this proceeding, an inverted rate design for Schedule R in summer. Presently, Schedule R summer rates are flat. BG&E would like to increase the charge for all usage over 500 kWh by about 10 percent higher than the first block rate. The purpose is to send a price signal and induce customers to "conserve relatively expensive summer load."

C. COS Study Issues

OPC, GSA and industrial customers object to BG&E's use of the 4 CP Min/Max method of allocating production plant. OPC says that the method overstates the cost to serve Schedule R. The industrials disagree, and present the results of several studies, all of which show that residential rates are below cost, Beth Steel and commercial rates are above it, and Schedule P and lighting users pay the cost of service. Industrial customers and GSA oppose BG&E's method of allocating production plant, but, unlike OPC, they are willing to accept it for purposes of this case.

OPC witness Stutz found that the 4 CP Min/Max method understates the return from the residential class. In lieu of BG&E's allocation of 33 percent on the basis of energy and 67 percent on the basis of demand, he recommends allocating generation-related costs 50 percent to energy and 50 percent to demand. He notes that BSU-2, BG&E's new base load capacity, is

about two times more expensive than marginal peaking capacity and, therefore, "must be justified on the basis of fuel savings." He also compares the costs per kW of Calvert Cliffs ($570) and a peaking unit close in age, Perryman ($113). This comparison, he says, supports an allocation of more than 67 percent of production plant to energy, but he proposes a 50/50 split only.

In essence, OPC witness Stutz proposes a peaker method of allocating production plant. We discussed this issue in some detail in Re Baltimore Gas & Electric Company, 75 Md. PSC 171 (1984) (Case No. 7770). In that proceeding, we outlined some principles and directed BG&E to present alternative allocation methods and studies in its next rate case. After considerable litigation, we rejected a peaker approach and adopted the 4 CP Min/Max method in Re Baltimore Gas & Electric Company, 78 Md. PSC 129 (1987) (Case No. 7973). We are not persuaded to reverse that decision.

OPC witness Stutz also objects to BG&E's allocation of administrative and general ("A & G") expense. He recommends allocating A & G costs on the basis of annual sales. The rationale is that there is "no really convincing argument . . . for allocating this cost" in any particular way. Thus, he chooses a method that is both "equitable" and consistent with his preference for "usage-sensitive ratemaking."

Beth Steel/GM witness Phillips takes exception to OPC's treatment of A & G expense. Mr. Stutz is "not allocating on the basis of cost," he says; rather, OPC is "assigning costs

to achieve a certain end result . . . ." BG&E functionalizes A & G into various categories, and allocates the categories consistent with the groupings. In contrast, Mr. Stutz "offers no sound rationale" and makes no attempt to establish a "direct link between A & G and energy usage." We agree with Mr. Phillips' analysis.

Industrial customers argue that BG&E's 1989 COS Study should be adjusted for BSU-2 only if the Commission approves a second step base rate or surcharge, not if there is another rate case or deferred accounting. The theory is that if revenue requirements do not reflect BSU-2, then neither should the COS study: MIG's witness Baron warns us about a potential "mismatch between the revenue requirement calculation used to develop the increase and the cost-of-service study utilized to allocate it." Given our treatment of BSU-2, however, the adjustment is no longer an issue.

In conclusion, we recognize that all COS studies and methods are judgmental. We also note that many non-cost considerations are relevant in the rate design process. Consistent with our approach in prior cases, we do not rely solely on any one COS study in this proceeding. Still, we place primary reliance on BG&E's 1989 COS study, adjusted for BSU-2.

D. Revenue Apportionment Among the Classes

BG&E earmarks the first $105.6 million of its proposed increase to meet the objective of bringing the customer classes to a 7 percent band around the system ROR. The

remainder of BG&E's phase one and two revenues are apportioned among the classes in relation to adjusted test year base revenues. Of course, even if we were to adopt BG&E's method without regard to notions of gradualism, we do not accept its phase-in proposal and rate requests. Thus, we cannot achieve the seven percent objective at this time.

Recognizing this possibility, and that BSU-2 rate relief may be authorized soon, industrial customers suggest that we treat the first $105.6 million of any non-BSU and BSU rate increase in the same way as BG&E did it in its phase-in plan. In other words, assuming a $75 million increase in the non-BSU-2 portion of the case, the industrials would apportion revenues in the following way. All $75 million of the non-BSU increase, and the first $30.6 million of the BSU-2 increase, would be used to move to the 7 percent band; the remainder of the BSU-2 increase would be apportioned on the basis of nonfuel revenues.

BOMA's witness Rosenberg insists that it is impossible to bring an above average return class into the 7 percent band under BG&E's methodology (unless the ROR goes down). He also inveighs against the use of a 7 percent band, arguing that no band should be used. BOMA believes that commercial (G and GL) rates are discriminatory because the class returns exceed the system ROR; and that there has been a lack of reasonable

movement to the system ROR. In arguing for relief, BOMA witnesses testified about the depressed status of the Baltimore office market and the effect of utility rates on building owners' operations.

BG&E witness Hargest testified about progress in moving schedules G and GL closer to the system ROR. Since 1983, rate increases to these classes have been less than the overall increases, and further movement to the system ROR is contemplated by the current request. He noted that electric increases to commercial customers between 1983 and 1989 have been very modest, and that BOMA's comparison of electric rates among cities is flawed. Compared to charges in 29 comparable cities, BG&E's commercial rates at various demand and energy levels rank between 9th and 12th lowest.

OPC also opposes the use of a 7 percent band. Unlike BOMA, however, OPC would widen the band to 10 percent. According to Mr. Stutz, a wider band is justified because of "weaknesses" in COS study results. The sources of those weaknesses include allocation methodologies and uncertainty in the input data, particularly peak demand data. A COS study is a "snapshot," the witness notes, but conditions may change over time. Uncertainty is reflected in a 10 percent band. To narrow it, then, is to assume an increase in accuracy in COS results, an assumption that is not supported by evidence.

In Case No. 7770, the Commission found that BG&E's goal of moving all classes to a 10 percent band about the system ROR was reasonable. We also said, however, that "[i]n the long run, an appropriate objective may be to move each customer class' rate of return toward a narrower margin above or below the average system rate of return."[21] We acted on that statement in Case No. 7973 by apportioning a reduction first to those classes that exceed the system ROR by more than seven percent. In BG&E's last rate proceeding, Case No. 8208, we took another step in the direction of a 7 percent band by assigning 80 percent of a rate increase to those classes that fell below it.

After considering this matter, we reject both BOMA's call for eliminating the 7 percent band now, and OPC's request to widen it. With respect to the suggestion about the first $105.6 million of the non-BSU and any BSU rate relief, we have concluded that both rate adjustments, not only the initial rate adjustment, should be utilized to move each class' embedded rate of return closer to the 7 percent band. We, therefore, generally adopt the methodology as proposed by Mr. Hargest with the following modification: the initial 50 percent of the non-BSU rate adjustment shall be apportioned to move the class rates of return to the band; the remaining 50 percent shall be apportioned among the classes in relation to test year base revenues adjusted to include amounts determined in the first

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21 Re Baltimore Gas & Elec. Co., 75 Md. PSC 171, 205 (1984).

step. If a rate adjustment is authorized in the spring of 1991 to recover the costs associated with BSU-2, BG&E shall apportion that increase to each class first to move the class rates of return to the band and to the classes within the band to maintain their position relative to the system average rate of return. Any remaining amount of the revenue requirement increase shall be apportioned among the classes in relation to test year base revenues, adjusted to include amounts previously apportioned. This apportionment will avoid undue increases to any one class, and yet lead to further movement by the classes to the system ROR.

E. Schedule R Issues

1. Customer Charge

BG&E proposes an increase in the customer charge from $3.50 to $5.00. This increase would move the charge about halfway to $6.55, which is the "estimated average monthly customer cost" as shown in the 1989 COS study. In contrast, the marginal customer cost is $16.83 per month.

OPC opposes the increase for two reasons. First, Mr. Stutz testified that increasing the customer charge reduces the value of rates as a price signal and may affect customer investment in conservation or load management adversely. Secondly, an increase in the customer charge may harm low usage customers, because this group generally has the "least potential to respond to changes in their bills by altering usage."

Mr. Hargest testified that the effect of OPC's proposal is to transfer $16.4 million of cost responsibility from customer to energy charges, adding another .174 cents to the kWh rate. Thus, over the course of a year, a customer who uses 1500 kWh per month will overpay embedded customer costs by $13.32. A 500 kWh customer will underpay by $7.56 annually.

After considering this issue, we agree with OPC that the residential customer charge should not be increased at this time. We recognize that one effect is to change the contribution to embedded customer costs by various customers. However, by shifting costs to energy rates, we can send better price signals. If those price signals induce the proper load shifting or conservation, all customers will benefit.

2. Inverted Summer Rates

BG&E proposes to charge about 10 percent more per kWh for all usage over 500 kWh in summer. The rationale is that existing flat rates provide no incentive to conserve expensive summer load; and that inverted rates better match rates and marginal costs. The residential class needs a better price signal, Mr. Hargest said, because it is the single largest contributing class to summer peak demands, about one-half of total summer peak. A time-of-use ("TOU") rate design sends the best signals, he concedes, but it is impractical to convert 900,000 people to TOU rates at one time.

Thus, BG&E's next best alternative is inverted summer rates. By setting the rate blocks above and below 500 kWh, BG&E is targeting usage over 1000 kWh per month, the breakeven point compared to flat rates. Mr. Hargest suggests that BG&E's design will send price signals to those customers with "more weather sensitive and discretionary usage." Ostensibly, customers using more than 1000 kWh per month have higher on peak consumption and usage characteristics similar to the air-conditioning subclass.

Staff favors flat summer rates. Mr. Levi says that the Company's cost studies do not support inverted rates: the studies do not show that BG&E's costs in summer go up with usage. Thus, inverted rates may induce uneconomic purchasing decisions, because BG&E would be pricing electricity at a higher rate than necessary, which inhibits economic consumption. Also, consumption over 500 kWh may be very economic if it occurs off-peak, but BG&E's proposal penalizes such usage. Finally, Mr. Levi opines that Schedule R provides sufficient price signals now, because summer rates are higher than winter, and because unlike winter's declining block rates, summer rates are flat.

OPC supports flat summer rates for purposes of this case, but for very different reasons. According to Mr. Stutz, the combination of an inclining summer rate and a declining winter rate sends a "mixed message." This factor, along with the large increase in the customer charge, is "likely to result

in customer confusion." Besides finding problems with the customer charge, Mr. Stutz says that BG&E's energy rates send the wrong signals; the only charge that is greater than marginal cost is the initial block rate in winter. Thus, Mr. Stutz proposes a different design, including flat summer rates, which is both simple and sends a clear message that summer usage is expensive.

Having reviewed the evidence on this issue, we are not persuaded by BG&E that any change is warranted at this time. We do not fc ilose the prospect of inverted summer rates; but we are no eady to adopt BG&E's proposal on the basis of this record. ontrary to OPC, we do not embrace the rationale about customer confusion; we think customers are fully capable of understanding the purpose of inverted rates. Rather, we share Staff's concerns. Before we would authorize inverted rates, BG&E must provide better cost and load data.

3. <u>Declining Winter (Non-Summer) Rates</u>

Every party seems to agree that the declining tail block of residential customers' winter rates should be eliminated, sooner or later. BG&E's winter peak is growing rapidly; BG&E may become winter peaking within the foreseeable future. Under the circumstances, Staff and People's Counsel argue that customers are misled by declining block rates, and that flat rate send a better price signal and place more

of the cost on the customer who causes it. Furthermore, flat rates are more apt to induce energy conservation, along with associated environmental benefits.

Staff, therefore, recommends the immediate elimination of the declining tail block in the non-summer period and OPC, on Br e. , recommends a phase-out: the announcement of a move to flat rates now, but an implementation in the next two rate cases.

The Company opposes the near immediate elimination of a winter tail block as both unjustified and inequitable and advocates a more gradual transition. Mr. Hargest testified that the Company's rate proposals are reflecting the gradual shift toward winter peak and that Schedule R's rate differentials between the non-summer initial and tail blocks have begun to converge. The Company expects to continue toward convergence of these rates in future cases. Mr. Hargest also points out that Staff and OPC's proposals would result in a substantial increase in the rate of return disparity between Schedule R heating and non-heating customers.

We have considered the arguments by the parties for and against a rapid elimination of the winter tail block in the R schedule. We are persuaded that it is appropriate to gradually phase-out the declining block. The "convergence" of the winter blocks in the Company's rate design is occurring through the application of the Company's 80/20 intraclass allocation methodology utilized by Mr. Hargest, but may require

a long period of time to accomplish. We agree with the need for a more rapid move to flat winter rates and, therefore, advise the Company to include in revised tariff filings in future cases a more rapid "convergence" than the Company anticipates.

4. Seasonal Differentials

Staff proposes a somewhat greater increase in summer rates relative to winter rates. According to Mr. Levi, his seasonal differential proposal better reflects the results of BG&E's marginal cost study. If BG&E prices electricity in this manner, he says, it will "provide a slightly larger inducement to conserve summer load than currently exists or than it proposes in this case."

Mr. Hargest testified that Staff's rate proposal "increases all summer bills by 23 percent or more, much higher than the Company's proposal." He also said that, by increasing summer revenues, Mr. Levi's proposal "appears quite contradictory to his concern of rising non-summer peak demands." OPC also shows the impact at various usage levels and claims that Staff's proposal presents a "very confusing picture," which is inconsistent with usage sensitive ratemaking.

We conclude that no changes should be made in the seasonal differential now. We do not resolve all issues about Staff's recommendation. Rather, we simply note our concern

about the bill impacts of Staff's proposal; and we invite Staff to address the issue of the relationship between the seasonal differential and the growing winter peak in a future case.

F. Schedule ES

Staff suggests that we close this rate schedule at the conclusion of this case. Mr. Levi says that Schedule ES has not been a cost-based alternative for residential customers for some time. Therefore, he urges us to phase it out gradually, to minimize the impact on existing customers. He urges us to close the schedule to new customers; ultimately, the service will end through attrition. The witness intimates that the service will not be missed: only two customers were added in 1989, while 35 customers left the schedule.

OPC witness Stutz disagrees with Staff on this issue. This schedule "provides an option for certain residential customers with low-average to average use" to limit their bills by restricting the level of service to 25 amperes. This program offers an alternative to customers in financial difficulty. Mr. Stutz believes that BG&E is not promoting the schedule, which may explain the recent lack of customer interest. Without some alternative in place to assist needy customers, Mr. Stutz would not close the schedule.

After considering this issue, we conclude that Schedule ES should be closed to new customers. When the Commission originally approved the creation of Schedule ES, we did

so on the expectation that the rates would provide a cost-based alternative from standard Schedule R service. However, as pointed out by Mr. Levi, Schedule ES is no longer cost-based, and has not been so for several years.

We favor the existence of an alternative residential schedule which makes available especially economical electric service. However, it is important that the rates for such alternative service be cost-based. Therefore, we will ask BG&E and our Staff to explore whether other alternatives exist for a special residential service which can be offered at lower rates than Schedule R, and which will conform to the Commission's basic principle of cost-based rates.

G. Schedule P Rate Design

MIG witness Baron suggests that Schedule P should be based on unit costs as derived from BG&E's embedded COS study. Consistent with that position, MIG supports BG&E's proposed customer charge for Schedule P because it reflects embedded costs. In contrast, MIG argues that Schedule P's other rates do not reflect either embedded or marginal costs, and it finds "no evidence" to support BG&E's contentions about consumption and investment decisions.

Thus, MIG urges us to reject the demand and energy charges of Schedule P. In its place, MIG would increase the demand charge at a rate of 1 1/2 times the average Schedule P increase with any remaining increase applied across the board

to energy charges. MIG also urges us to adopt a goal of further movement to cost-based rates in future cases. Finally, MIG asks the Commission to direct BG&E to perform a unit cost study for use in future rate design.

GM witness Phillips notes that Schedule P demand costs are below both embedded and marginal costs. In contrast, Schedule P energy rates are above both sets of costs. Accordingly, GM urges the Commission to increase demand charges by a greater percentage than BG&E's proposal with a concomitant smaller increase in energy charges.

BG&E witness Hargest testified that BG&E's rate design moves Schedule P rates closer to marginal costs in a more gradual manner. Under the Company's 80/20 proposal, BG&E increased Schedule P demand revenues "significantly more than energy revenues (17.7% vs. 13.8%)." The witness claims that industrial witnesses focus on cost only, and "ignore all principles of gradualism . . . ."

In testimony and argument, industrial customers object to various aspects of BG&E's intraclass rate design, especially the method of increasing demand and energy charges. The parties cite evidence about the relationships among rate elements and marginal or embedded costs, and argue that demand charges should be increased by a greater percentage than under BG&E's 80/20 method. The parties suggest that, given a smaller apportionment of revenues to this class, the Commission can restructure the rates and accommodate concerns about

gradualism. On brief, GSA joins the industrial argument, and cites similar evidence and raises the same objection to Schedule GL.

Based on this record, we are not prepared to abandon the Company's method of assigning the increase among the rate elements of schedules P and GL. While we cannot agree with Mr. Hargest's characterization that his adversaries "ignore" gradualism, we note that Beth Steel, MIG and GSA do not represent the customers on these schedules that impose small demands and use little energy. For purposes of this case, we find that BG&E's proposal is a reasonable attempt to accommodate the conflicting goals of minimizing the effects on all customers, and moving to rates that reflect marginal costs.

We add, however, that the parties raise a number of pertinent questions about the appropriate relationships among rate elements and costs. We conclude that these questions should be explored further. Before adopting any proposals to restructure schedules P and GL, we want a better record about the merits of alternative methods of intraclass rate design, and the effects on the entire class. Input from Staff on these issues would be most helpful.

Therefore, we hereby institute a second phase of this proceeding to receive additional information relating to the intraclass rate design of schedules P and GL. We intend to complete this phase expeditiously so that, to the extent we

deem appropriate, any change in rate design for these two schedules can be implemented at the time of the BSU-2 rate adjustment.

With respect to the request that we order BG&E to perform a unit cost study for MIG, we note our decision in Case No. 7770:

> The Commission notes the intervenors' discussion about the difficulty of producing precise cost-of-service studies and that such difficuly could be partially alleviated by the use of the Company's existing data base and computer program. Therefore, we will direct that upon reasonable notice from, and payment of a reasonable fee by, an intervenor in a future rate case, the Company shall produce a requested cost-of-servi.e study if such study can be readily obtained from the Company's existing data base and computer programs. 171 Md. PSC at 204.

Accordingly, if MIG affords reasonable notice, pays a sufficient fee, and the study can be "readily" produced, then BG&E shall provide it.

H. Beth Steel's Rates

As previously indicated, the Company has proposed the use of a 1989 calendar year cost of service study, while utilizing billing determinants based on the 12-month period ending July 31, 1990 to develop proposed rates. Bethlehem Steel Corporation, a single customer class, takes exception to the use of this data for developing the required increase in rates

for electric service. This challenge is predicated on the belief that this data will not be representative of operations in the near term and during the period that rates found appropriate in this proceeding will be in effect. Since such results are contrary to a fundamental ratemaking principle, Beth Steel recommends the rejection of the Company's proposal as it relates to its particular class.

According to Beth Steel's witness Phillips, Bethlehem Steel Corporation's revenue levels from August 1, 1989 through July 31, 1990 are not reflective of a representative test year or rate effective period. This opinion is based on the fact that Beth Steel s large "L" furnace was out of service from March 17, 1990 to July 1, 1990. Comparing the seven months ended July, 1990, with the seven months ended July, 1989, there was an approximate 34 percent decline in kilowatt-hour consumption resulting in a $6.9 million lower revenues being received by BG&E. According to Beth Steel, this unusual decrease in usage was caused by a planned maintenance outage of the "L" blast furnace, an event that normally occurs every six to seven years.

In recognition that the scheduled maintenance on the "L" furnace has been completed and will not again be required until 1996, and that normal operations have been resumed since July, 1990, Bethlehem argues that it is inappropriate to allocate BG&E costs on a 1989 cost of service study while using test year revenue based on an abnormally low level of billing

determinants for the 12-month period ended July 31, 1990. For these reasons, Bethlehem recommends using 1989 billing determinants to reflect the full operation of the "L" furnace.

The Company opposes any adjustment to the test year data to reflect a normal level of sales to Bethlehem. First, it suggests that the test year cost of service study is unrelated to the revenue requirement increase assigned to Bethlehem and that such apportionment to Bethlehem must be equalized with the increase imposed on Schedule P. Second, such an adjustment is contrary to the Commission's long-standing policy of not recognizing test year adjustments to sales for weather or economic conditions. Finally, the Company notes that the planned "L" furnace maintenance outage only reduced Bethlehem's test year sales by approximately a third of the difference between the test year and 1989.

After considering all of the arguments advanced by the parties in this proceeding, the Commission concludes that, in this instance, it is appropriate to reflect the normal operation of the "L" furnace in setting rates for the Bethlehem Steel Corporation.

In calculating the demand and supplemental kW rates as well as the kWh energy charge which are proposed for the rate-effective period, the Company has used billing determinants substantially lower than those experienced in 1989 or expected during the rate effective period. In our opinion, this method of calculation produces unit demand, supplement and

energy charges higher than otherwise required to support the Company's cost of service during the rate effective period. Since no party disputes the fact that the Bethlehem Steel Corporation's activities during the rate effective period will reflect the full operation of the "L" furnace, an adjustment is necessary to preclude an overrecovery of costs from Beth Steel.

In reaching this decision, the Commission is unable to accept the Company's assertion that acceptance of such an adjustment is contrary to the Commission's long-standing policy of not recognizing adjustments to test year sales -- for weather or economic conditions. While the Commission has previously discussed the difficulty in quantifying the effects that unusual weather conditions or economic recessions may have in evaluating representative test year operations, we have never foreclosed their consideration. Indeed, the Commission Staff was directed to examine methodologies for weather normalization which may be appropriate for Maryland utilities. See Re Baltimore Gas and Electric Company, Case No. 8208. In any event, the quantification difficulties discussed earlier are substantially different from the circumstances present here since the adjustment involves a single customer class, is reasonably known and certain, occurs infrequently and results in a more accurate collection of costs.

In authorizing an adjustment to the test year billing determinants, the Commission is aware that a difference of opinion exists between the parties relating to the effect of

the "L" furnace outage on test year sales. While the Company witness contends that the "L" furnace outage only affected Bethlehem sales by 110,000 MWh, or approximately one-third of the difference between 1989 and test year sales, Beth Steel maintains that Mr. Hargest's assessment that only one-third of the difference is due to the "L" furnace outage was unsupported by any exhibit or worksheet and is contrary to the evidence in the record. We believe that the appropriate resolution to this matter is to direct the Company, when submitting its compliance filing, to reflect the actual billing determinants for the 12-month period ending July 31, 1990, adjusted to reflect the full operation of the "L" furnace for the period from March 17 through July 1, 1990.

IT IS, THEREFORE, this 17th day of December, in the year Nineteen Hundred and Ninety, by the Public Service Commission of Maryland,

ORDERED: (1) That the fair value for ratemaking purposes of the electric utility property of Baltimore Gas and Electric Company, used and useful in rendering service to the public, averaged $3,729,236,000 for the 12-month period ended July 31, 1990.

(2) That the reasonable rate of return for Baltimore Gas and Electric Company is 9.94 percent and that rates for the future should be based upon this return applied to the fair value average rate base.

(3) That the existing rates of Baltimore Gas and Electric Company for electric service are no longer just and reasonable.

(4) That Baltimore Gas and Electric Company may file with the Commission amended schedules of rates for the sale of electricity at retail which shall result in an increase of not more than $76,964,000 in the gross annual electric revenues of the said Company.

(5) That the amended rate schedules to be submitted in accordance with ordered paragraph (4) shall conform with the guidelines set forth in the "Rate Design" section of this Order and shall be subject to acceptance by the Commission.

(6) That Baltimore Gas and Electric Company may file with the Commission amended schedules of rates for the sale of electricity at retail to recover the revenue requirement of Brandon Shores Unit 2, subject to the terms discussed in the Order.

(7) That Phase II of this proceeding is established to receive additional information relating to the intraclass rate design of schedules P and GL.

(8) That Baltimore Gas and Electric Company shall furnish this Commission each quarter with accurate and complete statements under oath, and in convenient form, setting forth the revenues and expenditures of the Company for the preceding 12-month period, such reports to be furnished

within forty-five (45) days following the last day of every quarterly period during the period the final Order entered in this proceeding remains effective.

AND IT IS FURTHER, ORDERED, that all motions not previously granted are hereby denied.

Frank O. Heintz

[illegible]

[illegible]

Commissioners

BALTIMORE GAS AND ELECTRIC COMPANY
RATE BASE
CASE NO. 8278
(Thousands of Dollars)

Unadjusted rate base	$3,893,042
Adjustments	
1. Terminal rate base	0
2. Unamortized gains on the sale of real estate	(902)
3. Load management programs	5,200
4. Effect on cash working capital of adjustments to NOI, rate base and capital costs, and revised rates	(648)
5. Revised lag days:	
Fuel, fringe benefit, O&M	(6,145)
6. Deferred fuel costs at April 1989 level:	
April 1989 balance	(153,567)
Pro forma amortizati'n	(4,950)
7. Deferred nuclear pro;ects	0
8. Keystone and Conem ugh invertory adjustment	(5,337)
9. Unamortized balance of pressu. 'er heater sleeve repairs	2,543
Total adjustments to rate base	(163,806)
Adjusted rate base	3,729,236

CASE NO. 8278
BALTIMORE GAS AND ELECTRIC COMPANY

Adjustments to Operating Income
for Twelve Months Ended July 31, 1990
(Thousands of Dollars)

1.	Advertising, nonoperating and lobbying expenses	1,503
2.	Return on accumulated decommissioning reserve	2,665
3.	Excess tipping fees	1,948
4.	Gains on the sale of real estate	310
5.	Storm damage	(276)
6.	AFUDC rate and base authorized in Case No. 8208	1,595
7.	Load management	(623)
8.	Deferred nuclear project costs	(293)
9.	Increase in taxes other than income taxes	(1,978)
10.	Reduced tax depreciation on Calvert Cliffs Unit 1	(3,525)
11.	Income tax rate differential for 1989 tax net operating loss	799
12.	Inventory adjustment at Keystone and Conemaugh	(4,163)
13.	Nonrecurring operating income effect of deferred nuclear projects	(2,339)
14.	Tax effect of pro forma interest	554
15.	Corporate Performance Awards	(517)
16.	Tariff Changes From Case No. 8208	5,523
17.	AFUDC	
	- On Property Placed In Service	(3,357)
	- On All CWIP	0
18.	Wage Increases (1990/1991)	(8,626)
19.	Health Care	(1,178)
20.	Tree-Trimming	0
21.	Purchased Capacity Charges	0
22.	Nuclear Decommissioning	(2,459)
23.	Postal Rates	(499)
24.	Excess Deferred Income Taxes	(678)
25.	Bresco Capacity Payments	0
26.	Uncollectible Accrual	0
27.	Federal Income Tax - Uncollectible Reserve	0
28.	Excess Overtime	0
29.	Employee Bonuses And Incentives	0
30.	Rate Case Expense	0
31.	Nuclear Operations And Maintenance Expenses	
	- Management Inefficiencies	0
	- Accelerated Maintenance	0
	- Pressurizer Heater Sleeve Repairs	3,450
	Amortization of Heater Sleeve	(141)
	- Alternate Operating Procedure	400
	- Electrical Cable Separation	887
	- Motor Operated Valves	1,415
	- Low Temperature Overpressure Protection	600
	- "Questionable" Costs	0
	Total Adjustments	(9,003)

STATE OF MARYLAND
PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF BALTIMORE GAS AND ELECTRIC COMPANY FOR REVISIONS IN ITS ELECTRIC RATES.	* * * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 8278

William A. Badger, Commissioner, Dissenting in part and concurring in part.

DEFERRED FUEL BALANCE

In this proceeding, the majority has rejected a Company proposal, supported by the Commission Staff, that it be permitted to include $207 million in rate base, representing the thirteen-month average net-of-tax deferred electric fuel balance during the test year. Instead, the majority decision limits rate base recognition to $53 million, a level which existed prior to the escalation of such balances due to the shutdown of the Calvert Cliffs Nuclear Plant.

The effect of this exclusion is to deny the recovery of $20 million associated with the financing of the deferred fuel balance. In reaching this decision, the majority advances, in part, a principle that an asset[1] that is ultimately found to have been imprudently incurred should not be permitted a recovery of capital costs.

I take strong exception to the majority finding for a number of reasons. First, it establishes an inappropriate linkage between the recovery of capital costs included in base rates for

[1]The asset is deferred fuel costs and represents the actual costs of fuel incurred by the Company but not yet passed through to ratepayers through the Company's fuel adjustment clause.

deferred fuel and the recovery of replacement fuel costs which are the subject of different statutory standards and litigated in separate proceedings.[2] Secondly, it may unfortunately send a signal to the financial markets that the Commission has pre-judged the recovery of replacement power costs, even though this issue is being litigated in an ongoing but separate proceeding that will probably not be finalized until the end of 1992. I have commented on the potential adverse effect of our decisions on the Company's credit ratings in the past. Baltimore Gas and Electric Co., Case No. 85205, Order No. 68797, issued May 17, 1990 (dissenting).

This latter concern should not be treated as an exercise in speculation. Indeed, three major financial investor services have recently lowered the credit ratings for the Company citing the continued financial pressure experienced by the Company relating to the extended outages at the Calvert Cliffs Nuclear facility. Standard & Poor's Credit Week report issued just 45 days ago observed:

> "Downside ratings prospects reflect uncertain regulatory treatment for ultimate recovery of replacement power costs and escalating Calvert Cliffs operating expenses."

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[2]This distinction has been recognized in past Company base rate proceedings and has been found fully consistent with Section 54F(e). Baltimore Gas and Electric Co., 80 Md. PSC 496, 501-03 (1989); Baltimore Gas and Electric Co., 80 Md. PSC 380, 386-[illegible] (1989); Baltimore Gas and Electric Co., 74 Md. P[illegible] 249, 2[illegible]-59 (1983) (noting that the genesis of the distinct[illegible] between allowing recovery in base rates of deferred [illegible] themselves and the financing costs associated with thos[illegible] [illegible]erred fuel costs came from an OPC witness, and that the [illegible]on agreed with the analysis of the OPC witness).

While the majority resolution benefits ratepayers for the short term, the downgrading of mortgage bonds, accompanied by higher interest rates, may translate into significant future rate increases for the Company's customers.

For these reasons, I would have provided for recovery of the financing costs associated with the deferred fuel balance. Such rate treatment would not be disadvantageous to ratepayers. If the Commission subsequently determines, based on a full evidentiary record in a fuel rate proceeding, that a lower deferred fuel recovery is appropriate, then the related financing costs can be returned to ratepayers through a credit to the deferred fuel account in an amount equal to the disallowed fuel costs plus interest thereon. In fact, this exact consumer protection remedy was ordered in the Company's last base rate proceeding. Baltimore Gas and Electric Co., supra, 80 Md. PSC at 503.

APPORTIONMENT OF REVENUE REQUIREMENTS - BETHLEHEM STEEL CORPORATION

As part of a continuing rate design process initiated several years ago, the Commission has appropriately determined that a portion of the revenue requirement should be disproportionately allocated to the various customer classes. This direction was considered necessary to achieve movement toward parity among the customer classes and insure that each class was responsible for the costs that they impose in the provision of electric service. In this regard, some classes were paying substantially less than their cost of service while other classes were contributing revenues considerably in excess of

their costs. Recognizing the judgmental nature of cost of service studies, the Commission determined that the revenue associated with each class embedded cost of service be gradually placed within a seven percent band around the system average rate of return.

I concur with the majority finding that this desirable rate design principle be continued in this proceeding. However, I disagree with the majority finding that the Bethlehem Steel Corporation, as a single customer class, should selectively be denied the benefits of the revenue allocation process. The record in this proceeding indicates that the Bethlehem Steel Corporation is contributing 118% of its assigned cost of service, while BG&E's other industrial customers assigned to Schedule P are providing revenues that support 97% of their incurred costs. In recent years, there has been an approximate ten percent increase in Bethlehem Steel's contributed revenue requirements over assigned cost of service while the contribution of the Schedule P customer class has remained stable, generally collecting less than its allocated cost of service.

In excluding Bethlehem from any of the allocation benefits, the majority accepts the Company's position that its contract with Bethlehem requires that Schedule P customers and Bethlehem receive the same percentage increase. In my opinion, the continued operation of this contractual arrangement frustrates the Commission's efforts to gradually eliminate the wide disparities that exist between BG&E's customer classes. The Commission's pursuit of this desirable objective is clearly in the public interest. The Commission obviously has the authority

to override agreements among private parties where provis...s are not in the public interest, as is the case in this proceeding. Potomac Edison Co., 68 Md. PSC 404 (1977) (Order No. 62502), 68 Md. PSC 367, 398 (1977) (Opinion accompanying Crder No. 62502), reh'g denied, 68 Md. PSC 661 (1977), aff'd, Eastalco Aluminum Co. v. Public Service Comm'n, Md. Ct. Sp. App., No. 352, Dec. 12, 1979, 44 Md. App. 754, (1979) (unreported) cert. denied, Md. Ct. App., Feb. 22, 1980, 287 Md. 75 (1980) cert. denied, 449 U. S. 831 (1980); Yeatman v. Towers, 126 Md. 513, 518-19 (1915). I would have included the Bethlehem Steel Corporation in the disproportionate revenue allocations to continue movement toward equalized class rates of return.

EXCERPT FROM:

Re Baltimore Gas and Electric Company

Case No. 8208
Order No. 68648

Maryland Public Service Commission
December 15, 1989

Nuclear Operations and Maintenance Expense

As was the situation in Case No. 8190, perhaps the most disputed item in this proceeding concerns the Company's request to include in operating expenses $26.5 million in increased nuclear operations and maintenance ("O&M") expense, compared to 1988 levels. Strong opposition to the proposed level of O&M expense has been reiterated in this proceeding, with People's Counsel vigorously objecting to such an adjustment on the grounds that the increased expenditures are directly attributable to the

Company's management problems, and that the Company has failed to show that such increased expenses are not attributable to imprudent management on its part. OPC also opposes the adjustment as being neither known nor measurable.

Staff, through witness Charles Kruft, Chief Auditor of the Commission's Accounting Division, provided additional testimony in this case urging the Commission to capitalize the entire proposed increase, as had Staff witness Lee earlier in these combined proceedings. Staff recommends such treatment as an interim measure as it indicates it is unable to make a conclusive determination regarding whether these increased O&M expenses should be expensed or capitalized. GSA notes its support for Staff's proposal, and further recommends that increased nuclear O&M costs above the level authorized in Case No. 8190 be accumulated as a deferred debit in Account No. 186, and excluded from rate base so that BG&E's stockholders rather than ratepayers would be responsible for the carrying charges on such costs pending an ultimate resolution as to the Company's nuclear expenditures.

In our decision in Case No. 8190, the Commission accepted the test year level of nuclear O&M expense as being necessary and proper expenses which the Company is entitled to recover under Section 69 of The PSC Law. Our acceptance of the test year level did not constitute a judgment on the reasonableness of the remainder of the Company's proposed adjustment (approximately $6.1 million of the total $26.5 million increase had actually been incurred by the Company during the April 1989 test year

utilized therein). In that decision, we also emphasized that any findings with regard to reasonableness were limited to O&M expenses, and that questions regarding the reasonableness of replacement power costs associated with the down time of the Calvert Cliffs Units would be independently determined in the Company's fuel rate proceedings. In regard to Staff's proposed capitalization of such expenditures, we indicated that we would generally be inclined to accept expensing of increased levels of necessary and proper expenses, unless individual non-recurring projects can be shown to be of sufficient magnitude to justify capitalization.

As noted above, for purposes of determining rates in this case, the Commission is utilizing the test year ending August 31, 1989, compared to the test year ending April 30, 1989 utilized in Case No. 8190. The record in this proceeding indicates that the Company has in fact expended \$18.3 million of the total projected \$26.5 million increase during the August test year, so that it is effectively proposing an \$8.2 million adjustment to the test year amount. However, while \$18.3 million of additional nuclear O&M expense was clearly incurred by the Company during the test year (compared to 1988 levels of such expense), OPC vigorously contests the inclusion of such amount (as well as the Company's projected further increase of \$8.2 million) to be recovered from ratepayers. OPC, who argues it has raised serious doubts regarding the prudence of these expenditures, contends the Company has failed to meet its burden of demonstrating that the increased level of O&M expense is not related to imprudence, and

contests whether such expenditures meet the "known and measurable" test.

OPC cites, with approval, the standard enunciated by the Federal Energy Regulatory Commission ("FERC") in Minnesota Power & Light Co., 11 FERC ¶ 61,132 at p. 61,645 (1980), regarding the burden of proof and the burden of going forward when imprudence is at issue:

> [U]tilities seeking a rate increase are not required to demonstrate in their case in chief that all expenditures were prudent unless the Commission's filing requirements, policy or other precedent otherwise require. However, where some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent.

We believe the FERC decision in MP&L provides a useful analytical framework for addressing the nuclear O&M issue in this case.

The crux of this dispute concerns whether these expenditures have been shown to be necessary and proper under Section 69 of the PSC Law. The Company contends that it has demonstrated that the test year level of expenditures, as well as its projected increase, are appropriate and well within comparable industry experience, and will actually prevail on an on-going basis into and beyond 1990 in order for the Company to operate Calvert Cliffs as an efficient, safe, and reliable plant. Furthermore, the Company maintains that if such level of expense had been incurred earlier, the amount would not be any lower today.

People's Counsel's arguments center on the management

problems that have been documented in the record of this proceeding with regard to operations at Calvert Cliffs, and which culminated in Calvert Cliffs being placed on the Nuclear Regulatory Commission's ("NRC") "watch list" in December 1988 (wherein the NRC designated Calvert Cliffs as a plant requiring close monitoring and increased NRC attention). The record shows that the Calvert Cliffs Units were later shut down, and neither of the two units have returned to service. However, the shutdowns were not directed by the NRC, but, according to BG&E, were made by the Company to address concerns revealed during a routine refueling outage.

OPC, through its witnesses, concentrates on the reports criticizing BG&E's management practices that culminated in the placement on the NRC watch list. OPC extensively cites conclusions of the NRC, including Systematic Assessment of Licensee Performance ("SALP") reports, with regard to performance problems at the Calvert Cliffs plant and the management responsibility therefor, as well as reports from the Institute of Nuclear Power Operations ("INPO"). This evidence, according to People's Counsel, demonstrates management imprudence and, therefore, the increases for nuclear O&M expense, originally dramatically heralded as a calendar year adjustment for the improvements required at Calvert Cliffs, should be rejected. Having raised the doubt, it is OPC's contention that BG&E has failed to prove that the $26.5 million were not incurred due to management imprudence.

In our opinion, OPC raised a sufficiently serious doubt regarding the adequacy of the Company's management performance and the $26.5 million in increased nuclear O&M expenses so that the Company has the clear burden to justify these expenses.

In regard to the allegations of imprudence, BG&E argues that a finding of prudence or imprudence requires a thoughtful decision based upon the facts and circumstances that were known, or should have been known, at the time a decision is made and prudence cannot be questioned based on outcomes. Therefore, the Company argues that the fact the Calvert Cliffs Units were placed on the NRC watch list by itself is insufficient evidence to find imprudence. Further, BG&E argues that the fact the Company did not act sooner to institute corrective action is insufficient to support a finding of imprudence.

BG&E maintains that it has demonstrated that the Company's management acted within the range of reasonable management decision-making in not acting earlier. Furthermore, the Company contends, even if one wishes to assume some level of management failure, there still is no logical nexus between the asserted deficiencies and the increase in operations and maintenance expenses. BG&E asserts that had the Company instituted the programs earlier, operations and maintenance expenses would not be lower today. According to the Company, the additional expenditures that are incurred are necessary for efficient operation of the Calvert Cliffs plant, and to disallow them on the ground that management failed to live up to the NRC's expectations would serve only to penalize the Company for doing

what it must do to restore service at its principal base load facility. To do so, BG&E argues, would be both punitive and counterproductive.

Initially, therefore, OPC alleges and BG&E responds to the allegation that management inaction constituted imprudence. A decision on that question by us at this time is required only if we find that there is a nexus between the increased O&M expense and the alleged imprudence.

As recognized in our decision in Case No. 8190, to exclude expenses from rates due to imprudence, a nexus must be established between the questionable expenses and the management deficiencies. Thus, expenses which could have been avoided by prudent management action are neither necessary nor proper, and would be properly excludable from rates. In this regard, any fines which the Company may have incurred from the NRC or other authorities are clearly expenses which cannot properly be passed on to ratepayers and must be absorbed by the Company's stockholders without reflection in rates. However, there are no fines or other similar penalties that have been passed on to ratepayers in this proceeding, despite OPC's attempt to analogize the Company's entire $26.5 million O&M increase to a civil penalty levied by the NRC.

To establish that there is no nexus, BG&E must prove that the increase in O&M expense is incurred for operational and procedural programs which should have been in place to assure safe operations under NRC standards and therefore, the increase in O&M expense was not incurred due to imprudence. If we make

such a finding, then those related expenses would be necessary and proper under Section 69(a), even though the costs would be incurred now, subsequent to the allegations in the various reports which fault management inaction.

Therefore, we turn to the second part of the argument, to resolve the question of whether BG&E has met its burden of proving that the new operational and procedural programs have prompted the increased expenditures and whether they would have been necessary or be substantially less costly, absent the alleged mismanagement. In this regard, in addition to its case-in-chief witnesses, the Company presented witnesses Doughty and Marmaroff, of the Nielsen-Wurster group, and Mr. Tim Martin, an expert in nuclear plant staffing, to provide an objective view of BG&E's request for increases in nuclear O&M expenses. To further explain the relationship between the proposed expenditures and the corrective actions, the witnesses provided the Performance Improvement Plan ("PIP"), which was issued by BG&E to the NRC on July 31, 1989, with an overview of BG&E's assessment of changes needed to comply with NRC requirements to achieve a safe, event-free performance at Calvert Cliffs. The PIP describes both prospective programs and efforts taken prior to the formulation of the PIP to improve management at Calvert Cliffs. The PIP outlines the programs that have been or would be undertaken to correct operational deficiencies.

For the calendar year 1989, approximately $12.5 million of the total projected $26.5 million calendar year increase were identified as associated with the PIP. The remainder of the

increase was described as ordinary operation and maintenance expense. Mr. Creel, in his testimony, also provided an explanation for the budgeted increases on a categorical basis wherein he explained each category and the associated expense. In the first stage of the proceeding, the focus of the investigation was centered on the reasonableness of the budget forecast, a matter not at issue in regard to the actual O&M expenditures incurred during the test year. Finally, when filing the actual August 31, 1989 test year data, Mr. Bange provided further detail as to the nature of the expenses incurred.

In viewing the record with regard to the problems experienced by the Company in the operation of its Calvert Cliffs units, we noted in Order No. 68591 that while the record clearly demonstrates criticisms of the Company's management operations by both the NRC and other authoritative sources, the criticism relates to management practices which generally seem to show the Company placed a greater emphasis on power production rather than adherence to procedures. For example, placement of the Company on the NRC's "watch list" appears to have been precipitated, in large part, by an investigation following an employee fatality at the plant. In that regard, the NRC noted that "recent significant operational events involving failures to properly utilize plant procedures have adversely impacted plant safety and in one instance resulted in a worker fatality. These events raise questions regarding the past licensee corrective action and the overall approach to safety at the facility". As we noted in Order No. 68591, such lax adherence to safety procedures cannot

be excused, and are matters that are clearly within the province of management that must be addressed by the Company. We do not conclude, however, that absent that laxity of management, any additional O&M expense was clearly avoidable. The programs and procedures which are detailed in the PIP and the general increase in nuclear O&M expense, the Company's testimony and evidence demonstrate should have been instituted or would have been incurred in order to assure safe operations at the Calvert Cliffs Units.

In fact, the record in this proceeding shows that while OPC, as well as other parties, have raised doubts regarding the Company's proposed adjustment for nuclear O&M expense, we find that the Company has met its burden in showing that test year O&M expenses were not incurred due to imprudence and are necessary and proper for the safe operation of the Calvert Cliffs units. While the Company has experienced operational management problems at Calvert Cliffs, these problems appear to be based upon BG&E's production oriented bias that gave insufficient emphasis to safety considerations. The evidence indicates that, in fact, the expenditures and safety programs now being implemented should have been undertaken previously by the Company. Furthermore, the record does not support a finding that any delays in implementation of such programs substantially increased their cost, or that they could have been avoided. In making the above finding, we note that the issue before us is to determine whether the test year level of O&M expense for nuclear generation is reasonable, necessary and proper. While the focus of the parties

has been the increase in expenditures over calendar year 1988 for the eight months January through August 1989, the Company notes that the record shows that it had already significantly increased its expenditures for nuclear O&M in 1988. We find that the test year level of expenses has been shown by the Company to be necessary and proper expenses that are properly recoverable under Section 69 of The PSC Law. On the record before us, we find the Company has justified the expenditures for the operation of its Calvert Cliffs plant.

In permitting these expenses, it is appropriate to observe that the NRC is charged with the design and administration of programs to insure the safety of the operation at Calvert Cliffs. However, unless the expenses could have been avoided, and, therefore, should be borne by the shareholders, the Commission has a concomitant responsibility to insure that the Company is provided with the funds necessary to implement these vital programs on a reasonable basis. The Commission accepts this responsibility and fully expects the Company to achieve the high standards of performance and safety at Calvert Cliffs for the benefit of its customers, as it has done in the past for so many years.

However, while we are accepting the test year level of O&M expenditures, the record does indicate that certain of those expenditures are related to start-up or foundational efforts, and accordingly may more properly be capitalized rather than expensed for ratemaking purposes. The Company takes the position that the increased O&M amounts incurred are properly expensed on the

Company's books under the guidelines of the FERC's Uniform System of Accounts. Cognizant of the Commission's statement in Order No. 68591 that we may consider individual nonrecurring projects that can be shown to be of sufficient magnitude to justify capitalization for ratemaking, the Company, on surrebuttal, identified four project phases that are components of recurring, ongoing activities, but which constitute start-up or foundation efforts involving a significant level of expenditures. If the Commission should find it appropriate to capitalize certain nuclear operations expense increases, the Company recommends that this treatment be limited to the projects identified by Mr. Bange, specifically:

Configuration Management Project
Procedures Upgrade Program
Procurement Program
Nuclear Information Project.

Although the actual increase in O&M expense during the eight months ended August 31, 1989 for these projects involved moderate amounts, a total of $3.5 million, total project expenditures are projected to rise to $107.6 million. We find that the above four programs qualify for the ratemaking exception as discussed in our Order No. 68591 and will reflect them in this decision on a capitalized basis.

Staff continues its recommendation that the entire incremental O&M expense be capitalized until such time as the questions raised in regard to the proper ratemaking treatment of these expenses are answered. However, in recognition of Order No. 68591, Staff sets forth two alternatives. The first one is

to capitalize the following three items in addition to those identified by the Company:

> $633,000 to insulate pipes in the Unit 2 containment chamber at Calvert Cliffs;
>
> $158,000 to install a new, replacement, upgraded coolant pump motor; and
>
> $504,000 to purchase and install 17 environmentally qualified in-core instrumentation assemblies in the Unit 2 reactor vessel.

The Company takes the position that these projects are properly expensed as maintenance and cites, in support thereof, the Operating Expense Instructions and Electric Plant Instruction 10, Additions and Retirements of Electric Plant, in The Uniform System of Accounts promulgated by the FERC. These maintenance projects seem to be unrelated to new operational programs. Under general ratemaking standards, we would not capitalize them unless the total expenditures substantially exceed those shown in the test year or some other rationale so that such projects should more properly be phased-in for rate recovery.

The second alternative offered by Staff is to capitalize all projects which are to be performed pursuant to the Performance Improvement Plan (PIP). The 1989 April projection vs. the 1988 actual expense indicated that $12.5 million of the then projected increase of $26.5 million would be required for the proposed activities. Staff notes that the expenditures associated with the PIP are of a different character than the remaining increases in O&M expense which have been characterized as "ordinary operation and maintenance expenses."

It is true that the four enumerated programs are not the only programs requiring start-up expenditures. The Company has argued, however, that subsequent to the start-up phase of such programs the operational expense will require continued expenditures at approximately the same level as the start-up expense. Accepting this argument, expensing the remaining programs described in the PIP may be the preferable treatment.

We are persuaded, based on our review of the evidence, that at this time neither the three additional items identified by Staff nor the remainder of the $12.5 million associated with the PIP should be capitalized. Rather, we agree with the Company that those items are appropriately expensed under the Uniform System of Accounts which, in this instance, we also believe provides an appropriate rationale for expensing those items for rate purposes.

The record indicates the four programs that are foundational in nature as those identified by the Company. Accordingly they will be capitalized, with the effect of increasing the test year level of net operating income by $2,246,000 while increasing rate base by $2,310,000. As to the method of capitalization, we agree with Staff's proposal which would allow a cash return on the capitalized portion and commence amortization at this time.

While we are accepting the test year level of nuclear O&M expense as being justified by the Company as necessary and proper for the operations of the plant, we decline to accept at this time the projected additional $8.2 million as an adjustment to the test year for known and measurable changes. (We note, in

this regard, that $4.8 million of this amount is projected for the projects for which we accept capitalization.) The Company's argument that the test year level of nuclear O&M expense will continue to increase in the rate-effective period may prove to be true, but in regard to the issue of further adjusting test year O&M for nuclear operations, which has been highly contested by the parties in this proceeding, it is our judgment not to accept further increases. The expenditures must be known and certain and subject to scrutiny by all parties in order to find they are reasonable, necessary and proper, and we decline to go beyond the test year amounts and include projected amounts as proposed by the Company.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

Case No. 8278

IN THE MATTER OF THE APPLICATION OF THE
BALTIMORE GAS AND ELECTRIC COMPANY
FOR REVISIONS IN ITS ELECTRIC RATES

PETITION FOR REHEARING OF
BALTIMORE GAS AND ELECTRIC COMPANY

Roger D. Redden
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Baltimore Gas and Electric Company

January 16, 1991

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page

Court Cases

Federal Energy Regulatory Commission Cases

Public Utility Commission Cases

BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

IN THE MATTER OF THE APPLICATION OF BALTIMORE GAS AND ELECTRIC COMPANY FOR REVISIONS IN ITS ELECTRIC RATES	* * * *	Case No. 8278

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PETITION FOR REHEARING OF
BALTIMORE GAS AND ELECTRIC COMPANY

Applicant Baltimore Gas and Electric Company ("BG&E" or "Company") hereby applies for rehearing pursuant to §86 of the Public Service Commission Law with respect to its Order No. 69054 issued December 17, 1990, hereinafter setting forth in detail the reasons for its application.

In applying for rehearing, the Company acknowledges the fact that both the Office of People's Counsel and Building Owners and Managers Association of Metropolitan Baltimore have filed notices of appeal from Order No. 69054 in the Circuit Court of Baltimore City and that this Commission has, in the past, considered that it was deprived of jurisdiction to exercise its statutory power to rehear and to modify its orders once any party to a proceeding perfected an appeal to court. See, e.g. Re Central Delivery Service of Washington, Inc. 71 Md. PSC 141, 142 (1980) and Re Potomac Electric Power Company, 71 Md. PSC 204, 205 (1980). The Company submits that the Commission has too narrowly interpreted its statutory powers and that it may rehear and modify its orders at least with respect to issues sought to be reheard by a party that has not appealed to court that are different from those raised on appeal, and perhaps with respect to any issue raised on application for rehearing.

An appropriate brief in support of the Company's position will be filed shortly after the filing of this application.

I.

DEFERRED FUEL

The Commission majority rejected BG&E's request to reflect in rate base the 13 month average balance of deferred electric fuel as of the end of the test period, limiting the Company instead to its balance as of April 30, 1989 used in Case No. 8208; it linked that choice to a time period prior to the shutdown of the Calvert Cliffs units due to the pressurizer hardware problem. The majority reasoned that it had engaged in a balancing process which took into account that it had: provided a return on some of the deferred fuel balance; provided a return on and of the nuclear plant; and not irreparably harmed the Company by the loss of the return on its deferred fuel balance because its financing costs are temporary. The majority further observed that BG&E did not ask for rehearing or appeal of the decision on that issue in Case No. 8208 and must therefore believe that the Commission's decision was equitable.

With due respect, the Company believes the Commission is incorrect on all points. First, as this request for rehearing most assuredly indicates, the Company does not accept the equity of a denial of a cash return on the full amount of its deferred electric fuel balance. Not to include the full amount as of the end of the test period -- the amount that reflects conditions expected to exist during the rate-effective period (T. 382) -- deprives the Company of a realistic opportunity to earn its authorized return. Second, the Company has been and will continue to be irreparably harmed by the disallowance of any portion of its of deferred fuel balance. BG&E has already sustained a loss of $20 million in revenue which is real, ongoing and permanent, as Mr. Brady made clear. (Co. Ex 7, p. 9.) The Commission's disallowance here denies recovery of an additional $20 million of revenue during the rate-effective period, which means that these "temporary" fluctuations will accumulate to more than $40 million; that amount is more than half of the rate increase approved in this

proceeding. There is no explanation as to why the deprivation of some $40 million is to be considered just a "temporary" phenomenon. If the Commission were to provide some means for later recovery of these costs, that would make the loss of such revenues temporary, but it would also raise the issue of retroactive ratemaking. The loss of these revenues is not really temporary and it does constitute a significant disallowance.

The impact of such a disallowance, as was pointed out in the dissenting opinion, is not idle speculation; the Company's bond rating has been lowered in the past year. Further, the signal to financial markets discussed in the dissent with respect to a predecision as to the ultimate recovery of replacement power costs, while it may not be intended, may nevertheless be so perceived. The very reason stated for choosing the average balance as of April 30, 1989 is that it precedes the recent outages at Calvert Cliffs, which necessarily links the limitation of the amount of the deferred electric fuel balance to the beginning point as of which the replacement power costs associated with the outages were incurred. This coincidence has an ominous undertone which, if unintended, needs most certainly to be erased.

Perhaps there is an unarticulated concern that providing a return on replacement power costs before the Commission has an opportunity to review fully all the §54F(f)(4) issues may result in ratepayers being charged for costs ultimately held not to have been reasonably incurred, even though later refunded with interest. This is somewhat analogous to Construction Work in Progress (CWIP), with respect to which the Commission has adopted a flexible policy of allowing a cash return whenever warranted by financial circumstances. However, when the Commission decides against a cash return on CWIP, it offers a second-best alternative: AFUDC. This provides the Company with some return, albeit a noncash one. In the instant situation, by not providing any return on the increase in that deferred balance accrued since April 1989, the Commission has denied the Company any opportunity to earn a fair return on this investment.

Accordingly, as a second-best alternative, the Commission should at the very least allow the Company to capitalize the carrying cost on the difference between the July 31, 1990 and the April 30, 1989 deferred electric fuel balances. Such a mechanism, although inferior to a cash return, would: (1) provide the Company with a more realistic opportunity to earn its authorized return; (2) protect ratepayers from having to pay anything at all on account of the capitalized amount associated with any portion of the deferred electric fuel balance that might later be disallowed and (3) make it abundantly clear to the financial community that the Commission has not in any way prejudged the fuel rate case.

Finally, it is simply not fair to conclude that the Company earning a return on and of its investment in Calvert Cliffs should be weighed against the plant's operating performance over a short period such as one year. Calvert Cliffs has provided the ratepayers of Central Maryland with very economic energy during all of its operating life. During much of that period, the plant has provided customers with reduced fuel costs through superior operation. Calvert Cliffs averaged a 75% capacity factor when the rest of the industry averaged about 62%. (Co. Ex. 3, p. 20.) Further, the plant has saved BG&E customers over $4.7 billion in fuel costs over its commercial life, although it cost only $778 million to build. (Co. Ex. 3, p. 21.) It is the absence of these fuel savings in 1989-90 that led to the increase in the deferred fuel balance. The mere fact that the Commission has allowed BG&E to continue to receive a return on and of its capital during this period does not compensate the Company for the financing costs associated with the increase in the deferred fuel balance. Indeed, refusal to provide some return really imposes a penalty on the Company and on a plant that has been most economic to ratepayers, a plant that has generated fuel savings that have in effect paid for the cost of the plant more than five times.

The majority's decision to limit the amount of deferred electric fuel does not provide a fair balance between the interests of stockholders and ratepayers in that it fails to provide a reasonable opportunity for the Company to earn a return on the investment made to provide service to ratepayers. Part of that balance could be restored if the Commission

were to allow capitalization of a return on the difference between the deferred electric fuel balance ending July 31, 1990 and the amount as of April 30, 1989, thereby providing the Company with a more reasonable opportunity to earn its authorized return while insulating customers even from exposure to refundable overpayment (the customer would only pay for the financing costs when and if the Commission ultimately determined that the underlying replacement power costs were prudently incurred) and also sending an unambiguously "right" signal to the financial community.

II.

THE COMMISSION SHOULD RECONSIDER ITS INDIVIDUAL ADJUSTMENTS TO TEST YEAR OPERATION AND MAINTENANCE EXPENSE

A.

The On-Going Level of O&M Expense Is the Center of Inquiry

Following an extensive examination of the Company's case for acceptance of its test period, per-books operation and maintenance expenses for rate-making purposes, the Commission concluded (at page 67) "that the Company's overall level of test year nuclear O&M expenses is reasonably representative of expenses which will be incurred during the rate-effective period." Having reached that conclusion, the Commission's inquiry should have ended. However, the Commission continued its examination of the subject and eventually reduced nuclear O&M expenses by $3.3 million for an extraordinary maintenance item and $3.3 million with respect to four "hardware and procedural deficiencies."

The Company submits that, when the Commission made its determination that the overall test year level of O&M expense is appropriate for the rate-effective period, it was an improper application of rate-making standards for it then to reduce that level on account of specific items when the record disclosed that the level of O&M expenses for the

rate-effective period will be even higher than it was during the test year. The whole concept of use of an historical test year as a guide to rate-making is intended to take booked revenues, expenses and other costs for a recent period and adjust them so as to create a reasonable basis of comparison for conditions that may be expected to prevail during the future period in which revised rates are to be effective. The use of a recent historical period is designed to approximate future conditions. The Company's request for nuclear O&M expense in this case addressed and satisfied these rate-making standards. The dollar amount of the request was limited to the amount actually expended for those purposes during the test year -- $142 million -- although the Company also presented its 1991 budget estimate of those expenses under the assumption that both units would be back in operation in 1991 -- $158 million. Both the test year actual level of nuclear O&M expenses and that projected for the rate-effective period, as they are the levels necessary to accomplish the activities required to maintain and operate the plant in a safe, reliable and efficient manner, meet the "necessary and proper" test of Section 69 of the PSC Law.

It cannot be too emphatically stressed that it is the level of such expense that is the center of any rate inquiry. One may accept as a truism that few of the individual items of maintenance work will be specifically repeated within the rate-effective period contemplated in this proceeding, although some of the programs may be on-going.

To isolate individual items of expense for disallowance has, in this context, the effective impact of a penalty and effects a form of retroactive rate-making. As Mr. Bange pointed out in rebuttal, the Company will have absorbed, without any rate recovery, $116 million of nuclear O&M expenditures during the three-year period 1989-1991 (Co. Ex. 19, p. 15; Ex. RMB-9), including all test-year expense increases in excess of the amount requested by the Company in Case No. 8208. Because the Company has been undercollecting, and will continue to undercollect, for its actual nuclear O&M expenditures, disallowing these individual items -- for which nothing was being collected from rate-payers anyway -- means

that there is a negative "double counting" which results in a disallowance of costs which would never have been recovered.

B.

In Disallowing the Four Items Identified as "Hardware and Procedural Deficiencies," the Commission Misapplied the Prudence Standard by Inappropriately Relying on NRC Documents

The Company submits that the Commission, in reviewing the four discrete items of maintenance expense at pages 70-84 of its Order, inappropriately utilized a standard of care nearing perfection for its review of management prudence. The Commission specifically relied on documents generated for or by the NRC, including Licensee Event Reports (LERs) and Notices of Violation (NOVs), as the evidence that the Company's management had not acted with adequate prudence to justify allowance of the subject expenditures for rate-making purposes. For the reasons set out below, it is submitted that such reliance on these documents is inappropriate. Moreover, by so relying on these documents, the Commission has implicitly utilized an NRC standard of care that is inappropriate in a state economic regulatory proceeding.

We are dealing here with the "reasonable person" standard well-described in the New England Power Co. case, 31 FERC (CCH) ¶61,047 at 61,084 (1985):

> [W]e reiterate that managers of a utility have broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers. In performing our duty to determine the prudence of specific costs, the appropriate test to be used is whether they are costs which a reasonable utility management (or that of another jurisdictional entity) would have made, in good faith, under the same circumstances, and at the relevant point in time. We note that while in hindsight it may be clear that a management decision was wrong, our task is to review the prudency of the utility's actions and the costs resulting therefrom based on the particular circumstances existing either at the time the challenged costs were actually incurred, or the time the utility became committed to incur those expenses.

This is not a standard of perfection. Even if a decision is found, in hindsight, to be incorrect, if that decision was reasonable when it was made, it has satisfied this standard.

But the Commission, by its very reliance on NRC documents, has, in effect, adopted the higher standard of care reserved for NRC safety-related reviews, a standard not appropriate for a rate proceeding. The primary purpose of a rate proceeding is to regulate the economic relationship between a utility and the public, and to assure the public that a utility's service monopoly will not result in unreasonably high utility costs. See, e.g., Philadelphia Electric Co. v. Pennsylvania Public Utility Commission, 5?8 A.2d 98, 101 (1988).[1] The severe, safety oriented, hindsight-directed, root-cause-focused language to be found in reports by or to the NRC should not be utilized in the context of a prudence evaluation for rate-making purposes; that language is fairly indicative only of that agency's drive for perfection in safety compliance enforcement. For the Commission to do otherwise would require the Company to practice flawless safety techniques while simultaneously maximizing production capacity. Id., p. 101. This is a dual standard very difficult to attain and impossible to meet at all times and in all instances.

These documents, including Inspection Reports (IR's), Systematic Assessment of Licensee Performance (SALP's), as well as LERs and NOVs, exist to improve plant safety. In order to perform this crucial safety-related function they must be critical and identify both potential problem areas and areas where improvements can be made. These documents are intended to be used by technical experts within the nuclear industry and they are often written with the assumption of technical expertise and are frequently one-sided. The NRC-generated documents are not reviewed by the Company for accuracy, completeness or Company concurrence prior to their issuance. Because these documents can be misinterpreted, it is simply not appropriate to use them as evidence of

[1] Reversed on appeal Pennsylvania Public Utility Commission v. Philadelphia Electric Co., 561 A.2d 1224 (1989), but with the Supreme Court stating that the Commonwealth Court "correctly stated the various principles of law," although applying them incorrectly. Id., p. 1227.

imprudence, even when considered along with Company's responses to [illegible] Open Items, or SALP findings. These responses are typically aimed at corrective [illegible] and not in anticipation or explication of a defensive response as to how or why a particular violation may have occurred. Moreover, it is often necessary to discuss technical topics with the technical experts to gain a full and complete understanding of the issues involved and the actions taken. Critical as they were on the written record, OPC witnesses, Messrs. Kononetz and Hooper, on whose testimony the PSC relied, conducted no interviews of plant personnel.

Company-generated reports, such as LERs, fulfill a co-ordinate function of improving safety compliance. One purpose of LERs is to notify the NRC of a recent discovery or event which might have generic industry implications. By its nature, an LER must be a critical assessment of an event to establish root causes of any deficiency and appropriate corrective actions. However, the LER will not assess the prudence of management actions or activities at the time the defective condition was established.

Reliance on these documents as evidence of imprudence has been found inappropriate in other jurisdictions. Most recently, the Illinois Commerce Commission decided that NRC SALP Reports could not be used alone to establish whether Commonwealth Edison Company operated a nuclear plant in an imprudent manner. Illinois Commerce Commission v. Commonwealth Edison Co., Case No. 86-0511 (Nov. 7, 1990) (Relevant portions attached as Appendix 1). The Company argued against the Hearing Examiner's reliance on SALP Reports. Although the Illinois Commission agreed with the Hearing Examiner that it is appropriate to take administrative notice of the SALP Reports, it stated: (at pp. 11-12).

> The SALP Reports, however by themselves, cannot establish whether Edison operated its nuclear units individually, or collectively, in an imprudent manner.

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> While the Commission should take administrative notice of these NRC reports, they cannot be given much evidentiary weight without appropriate testimony and cross-examination.

The Commission found that the primary thrust of such reports is directed towards "safety performance," and that they are useful in: occasional discussion of specific outages; establishment of trends in safety performance; and gaining a general perception as to the Company's nuclear unit operations and its regard for safety. Id., p. 11. The Commission also found the SALP Reports to be inconsistent: while a Category 3 rating is the lowest given by the NRC, the agency states in its description of that rating that management performance is "acceptable." Id., p. 12. "SALP Reports do not indicate that Category 3 ratings are the worst ratings, or that such ratings show imprudency of nuclear plant operation." Id.

In another case, the Supreme Court of Florida held that a NOV should not have been the primary source of evidence for a finding of imprudence by the Florida Public Service Commission. Florida Power Corp. v. Public Service Commission, 424 So. 2d 745, (1982). The case involved extension of an outage after a test weight was dropped onto a fuel assembly because the hook used was not designed to carry the full load of the test weight. Replacement power costs of $12,859,251 were incurred during the extension.

The Court, recognizing that the NRC's NOV criticized plant procedures for the labeling and testing of hooks and that the Company's Nuclear General Review Committee (NGRC) report concluded that the repair work was safety-related, found, however, that "the NRC's notice and the NGRC's report were both issued after the accident had occurred. Hindsight should not serve as the basis for liability in this instance." Id., p. 747. The Court specifically recognized that the NRC's notice was concerned solely with safety-related matters, consistent with the NRC's "limited" scope of responsibility for nuclear safety. Thus, the notice "involved a very different risk and much higher standard of care than involved in this case." Id.

On remand, the PSC found there was a basis, independent of the NRC and NGRC documents, for determining that the procedures were deficient. The Court again reversed, finding that the PSC had not shown that management acted unreasonably at the time, leaving the PSC's findings unsupported by competent substantial evidence. Florida Power Corp. v. Public Service Commission, 456 So. 2d 451, 452 (1984).

Placing heavy reliance on the language of any of the subject documents during a rate case pushes those documents beyond their intended function, giving them a meaning and a role for which they were never intended. This could have a potentially chilling effect on utility personnel responsible for identifying, analyzing and reporting on safety issues. Moreover, because these documents determine the adequacy of licensee activities, processes or hardware, based on current regulatory or industry standards, they do not determine the adequacy of past plant conditions or the prudence of past licensee actions.

C.

Specific Issues

Abnormal Operating Procedure - 9 (AOP-9):

The Commission disallowed the costs associated with the AOP-9 procedural issue based on a conclusion that the AOP-9 LER root cause and contributing cause discussion (p. 74) "clearly indicate management inattention to a procedure which has safety implications for the operation of Calvert Cliffs," having previously noted that "BG&E's own analysis shows that from 1984 for Unit 1, and from 1986 for Unit 2, the Company failed to adequately review the NRC's Appendix R procedures..."

It is submitted that both this conclusion and its basis involve an incorrect analysis of the record. A review of the history of Appendix R is here appropriate. The fire at Brown's Ferry in 1975 identified the need to consider the effects of fire in locations where the ability safely to control and/or shut down the plant may be jeopardized by a single event. (Co. Ex. 14, p. 31.) Prior to that time, normal fire safety practices and standards were

applied, and the NRC relied on the licensee to protect against fire damage and on the fire underwriters to provide the review of the licensee's protection measures. Increased NRC involvement after the Brown's Ferry fire led to the issuance of Appendix R in 1981. In 1984, BG&E was the first utility successfully to complete an Appendix R inspection by the NRC without incurring a violation. (Co. Ex. 14, p. 31.) Under NRC regulations and practices, periodic inspections have been conducted of various aspects of the Calvert Cliffs fire protection program since 1984. (Co. Ex. 14, p. 26.) During the 1988 inspection a comment was made concerning the fragmentation of fire protection knowledge and responsibilities and, although this was not a violation and not pertinent to the simultaneous dual-unit shutdown issue, by January of 1989 the Company had responded, designating a Fire Protection Engineer within the Configuration Management Unit to consolidate and review the fire protection program. In 1989, the Special Team Inspection (STI) also looked into this area and did a walk-through of the procedure. (OPC Ex. 8, Ref. Doc. 9, p. 4.) One unrelated finding concerning AOP-9 was noted. (Co. Ex. 14, p. 26.)

Moreover, management could not have been alerted to the subject deficiency through any change or addition to the NRC's regulations. In 1982 the NRC issued its Safety Evaluation Report, accepting the Company's Appendix R program, including its procedures. Since 1984, (when the original Appendix R inspection was satisfactorily completed) there have been no changes to the original Appendix R requirements signalling any need for management to review the program. (T. 2269.) Furthermore, neither the NRC inspection manuals nor the NRC's Generic Letter 86-10, "Implementation of Fire Protection Requirements", discuss simultaneous dual unit shutdown for common control rooms.

Not only has the NRC reviewed this program extensively, other mechanisms were, and are, in place to provide management with appropriate feedback. The Company can demonstrate that Technical Specifications require internal audits to be conducted annually by qualified offsite licensee personnel, biennially by Quality Assurance, and

triennially by an outside fire protection consultant. Another Technical Specification requires that certain safety-related procedures be reviewed every two years. Furthermore, through regularly held Operator training classes on this procedure, the Operators have an opportunity to provide comments on its adequacy. And although AOP-9 had not been revised since 1984 (Unit 1) or 1986 (Unit 2), changes to the procedure had been incorporated via the Calvert Cliffs Operation Manual Change Report (OPC Ex. 8, Ref. Doc. 60, p. 7), which shows that the procedure was not left stagnant. Processes are in place to insure that the original Appendix R requirements are not violated. The Design Engineering Section is responsible for assessing the effects of design changes on the fire protection program. The Company can also demonstrate participation in industry-wide fire protection activities and that it was not aware of any other utility that had performed such a dual unit validation, or of any concerns about the issue.

None of these various feedback mechanisms or processes indicated any deficiencies in AOP-9. The subject deficiency was self-identified after the creation of a project team within the Configuration Management Unit which had as its objective the "verification and clarification of the basis for our Alternate Safe Shutdown procedure (AOP-9)." (OPC Ex. 8, Ref. Doc. 60, p. 3.) This objective was in line with the mission of the newly formed Configuration Management Unit to "consolidate the Calvert Cliffs design basis to enhance our ability to assess the impact of proposed plant activities on the design basis." (OPC Ex. 8, Ref. Doc. 60, p. 3.) The Company's creation of the Configuration Management Unit in 1989 is typical of industry initiatives for plants of Calvert Cliffs vintage. (Co. Ex. 14, p. 29.) The choice of Appendix R as a starting point is not necessarily indicative of a concern about Appendix R but, rather, shows that Appendix R, as a relatively recent regulation, was considered to be an appropriate place from which the Configuration Management Unit could begin to carry out its mission. AOP-9 was then chosen as one area within Appendix R on which the project team would focus. (Co. Ex. 14, p. 26.)

Accordingly, the identification of the deficiency in AOP-9 is more properly an example of proactive management attention and the effect of self-assessment programs, as in the situation of BG&E's initial Appendix R response, rather than the reverse, as suggested by the Commission. The LER concluded that "The root cause of this event . . . is the failure to perform an adequate, dual unit validation and verification of AOP-9." (OPC Ex. 8, Ref. Doc. 60, p. 6.) The wording of the LER was intended to indicate that the need for simultaneous dual unit validation was not explicity identified in the regulations. It is improper to conclude that the Company failed to be responsibe to known regulatory requirements. In fact, the value of simultaneous dual unit validation was highlighted through the Company's analysis. Furthermore, in order for the Company to be deemed "inattentive," one must conclude that it should have understood the necessity of performing the dual unit validation at the onset of the implementation of Appendix R requirements. But not once, from any of the inspections, audits or other feedback mechanisms, has the issue of dual unit validation (which is the reason for the AOP-9 expenditures) arisen.

Nor do we believe it appropriate to use an LER written in 1989 and applying 1989 standards to fault management for conduct occurring prior to 1989. Mr. Vollmer described how original nuclear plant procedures have evolved over time. Original procedures, for older plants such as Calvert Cliffs, are not consistent with present-day standards for procedures in terms of scope, depth or style. While these procedures have been periodically reviewed, and revised as necessary, at some point a programmatic effort must be undertaken to enhance the overall quality and consistency of procedures. (Co. Ex. 14, p. 17.) Thus, management actions must be judged by the procedure implementation practices typical to and acceptable in the time frame of their conduct and not by present day practices. The LER, in evaluating the subject procedure, used current standards for writing and validating procedures which were not typical during the original implementation of the Appendix R requirements. To insist that the Company should have known to utilize 1989

procedural timeline analysis and simultaneous dual unit validation at an earlier point in time is to hold the Company to an unreasonable standard of performance.

Finally, the Commission approach fails to take into account certain routine aspects of ongoing processes within a nuclear plant. Costs associated with retraining should not be disallowed; operators are required to undergo almost continuous training in order to maintain their qualifications and ensure that the plant is operated safely. According to TB&A Reference Document No. 72, a memo from C. R. Sinopoli dated October 4, 1989, much of the training was in the form of assigned readings, which is part of the normal routine, and for which no additional time need be allotted. (OPC Ex. 8, Ref. Doc. 72.) Nor is there a basis to conclude that costs associated with hardware modifications could have been reduced if implemented earlier, and certainly this is no basis to conclude that they should not have been incurred at all since they were necessary to meet regulatory requirements. (Co. Ex. 14, p. 28.) Also, Mr. Vollmer described the ever-changing environment in which procedures exist and explained the distinction between the required periodic reviews and normal updates and a comprehensive upgrade program of all procedures. (T. 2252-53.) The Company received no signal that such a comprehensive program was needed until late 1988. (T. 2248-49; 2270.)

Additional management attention, whether to IR's, QA reports, existing regulations, or to standard industry practices, would not have identified this deficiency with the original Appendix R implementation, because simultaneous dual unit validation was not a normal issue. The fact that inconsistencies are identified internally as a result of a proactive review demonstrates that the management process is effective, not inattentive. (Co. Ex. 14, p. 29.)

Electrical Cable Separation:

In reviewing the specifics of the electrical cable separation issue raised by People's Counsel, the Commission appears to have gained a incorrect impression as to the

scope of mandatory separation prior to 1989. This is indicated by the Commission's observation at page 77 of its Order that the Company witnesses did not show any changes that would allow electrical cables to be closer than three feet horizontally or five feet vertically.

What must be borne in mind here is that these criteria did not apply to all cables, but pursuant to the Updated Final ty Analysis Report (UFSAR) and CCNPP Stand rd E-406, and as applied in the origin. nstruction of the plant, these criteria were directed solely at assuring separation between redundant, that is, safety-related cables. However, as subsequently interpreted by the NRC inspectors in 1989, the criteria were expanded to apply to the spacing between safety-related and non-safety-related cables and to the cable trays, as well. This, we submit, was clearly an imposition of a higher standard for the first time in 1989. Accordingly, the Commission's subsequent conclusion in its opinion -- that the original documents were faulty and that deficiencies should have been discovered at an earlier point in time -- imposes an improperly severe criticism on plant management. Prior to the expanded interpretation of the separation criteria during the NRC inspection in 1989 there were no deficiencies to be identified in the original documents. Only through application of this expanded interpretation of cable separation criteria by NRC inspectors can fault be found with original documents.

While it is true that this situation is not readily apparent from review of the NOV (which was the document primarily relied on by People's Counsel's experts and, we believe, by the Commission), this more comprehensive examination of the subject illustrates the difficulty and misunderstanding that may be encountered in the course of reliance on NRC documents alone in the context of a prudence review.

The NOV identified five cable separation discrepancies. One cable tray did not have adequate separation because of a damaged fire barrier. (OPC Ex. 8, Ref. Doc. 62.) Two other discrepancies involved cables routed in the wrong trays. These cables were not

routed in accordance with the requirements of E-406; the design/construction requirements did exist, but were not followed during this modification.

The remaining two discrepancies were identified as a result of the changing regulatory environment described by Messrs. Vollmer (Co. Ex. 14, p. 32-33) and Doughty and Marmaroff. (Co. Ex. 15, p. 40-41.) When the plant was originally constructed, no installation separation criteria were applied to non-safety-related cable trays. According to the Tenera study, (commissioned prior to the NOV), these original construction standards were appropriate for a plant of that vintage. (Co. Ex. 15, p. 40.) As Mr. Vollmer explained, the nuclear industry separation philosophy is to provide physical separation between redundant circuits to assure that, if a failure occurs, only one of the redundant circuits is jeopardized. (Co. Ex. 15, p. 30.) The reasoning behind the original design was that the required redundancy could not be violated by a non-safety-related cable tray being adjacent to a safety-related cable tray.

Nevertheless, as previously indicated, the NRC inspection applied the criteria for redundant cable tray separation to safety-related and non-safety-related cables and trays. This was a change in application. The Tenera study quoted in the rebuttal testimony of Messrs. Doughty and Marmaroff explained that if a plant's Updated Final Safety Analysis Report is silent as to certain specific separation conditions, the NRC applies its current interpretation of the requirements. (Co. Ex. 15, p. 41.) On that basis, at least, it is not surprising that discrepancies were found; two of the subject trays were never intended to meet the 3- and 5-foot separation criteria. During subsequent walkdowns, similar arrangements were identified, evaluated, and accepted 'as is' (i.e. within 3 and 5 feet) by the project team. In IR 90-05, the Inspector described BG&E's position that safety-related cables need not be separated from non-safety-related cables because non-safety-related cables were considered to be non-redundant. Thus, the NRC understands the Company's position and resolution of the separation of safety-related and non-safety-related cables and cable trays. The NRC review of the matter indicates an application of evolving regulatory

standards for which the Company should not be penalized. Furthermore, both IR 90-05 and an earlier inspection report, IR 90-02, commended the Company's progress in resolving the cable separation issue. (Co. Ex. 15, p. 39-40.) (Neither is in evidence, but they are included in the TB&A Reference Document list as part of Document Number 20.) Possibility of earlier discovery cannot, in such a situation, become a subject for reasonable debate; it is expanded interpretation of the design criteria by the regulator that creates the "discovery."

In the case of the damaged fire barrier, there was no deficiency in either the original construction documents or installation practices. It was simply a case of "normal wear and tear" occurring and that should be considered an allowable cost. As Mr. Kononetz acknowledged, barriers do become damaged through aging and the impact of the work activities; associated costs are a "reasonable subcomponent" of total electrical cable separation costs. (T. 2127, 2129.) Much of the cost actually associated with this program is the cost of repairing and maintaining the fire barriers and not, as alleged by Messrs. Kononetz and Hooper, the result of reworking the cable installation due to original design deficiencies. (Co. Ex. 15, p. 41-42.)

Finally, the deficiency related to the recent plant modification represented neither a longstanding defect nor a discrepancy in original documents. Disallowance of these costs would plainly hold the Company to a standard of perfection; as the Commission has noted (Order p. 75) even Mr. Kononetz acknowledged that these types of mistakes will occur and considered the lack of timeliness to be the main concern.

The Company's response to this issue -- a complete walk-down -- was prompt and, indeed, appropriate even to Mr. Kononetz. (T. 2170.) To disallow the costs associated with electrical cable separation not only holds the Company to a perfection standard (no mistakes allowed in the modification process), but also penalizes the Company both for maintaining the plant in its as-built condition (repair of damaged fire barriers and other project costs are true maintenance costs) and for not anticipating each evolution of regulatory standards for safety compliance.

Motor Operated Valves (MOVs):

The Commission's conclusion (p. 80) "that there were not adequate procedures for lubrication of MOVs which are necessary for the safe operation of a nuclear power plant" and that the "Company's MOV maintenance program was deficient" appears to be based on the June 16, 1989 NOV which found that the Company had no procedural requirements specifying "the frequency of inspections or the necessary criteria for stem lubrication of the actuators...". (OPC Ex. 8, Ref. Doc. 64, App. A.) It is submitted that disallowance of all costs associated with the MOV program clearly illustrates a misunderstanding of the NOV, because the costs incurred during the test period were not associated with the violation but, rather, with on-going maintenance activities.

The NOV resulted from a special NRC inspection undertaken to review the Company's corrective actions that resulted from IE Bulletin 85-03 regarding generic industry concerns about improper limit switch and torque switch settings in MOVs. The scope of the Bulletin was limited to the plant's 24 High Pressure Safety Injection System valves, 12 on each Unit. The MOVs on which the Company performed maintenance during the test year included not only the 12 valves on Unit 1 but also many other MOVs. The costs incurred in the test year for MOV maintenance, and torque switch replacements, were only about $600,000 (T. 2294), not $1,415,000 (the amount disallowed pursuant to the Order).

The NOV cites BG&E for a violation in its stem lubrication maintenance practices for the IE Bulletin 85-03 valves. (OPC Ex. 8, Ref. Doc. 64, App. A.) Stem lubrication is a simple process not associated with the main gear box assembly and does not involve even opening the valve actuator.

The Inspection Report on which the NOV was based also addressed the lubrication of the main gear box assembly and identified the "potential" for lubrication deficiencies; this was not an element of the NOV. (OPC Ex. 8, Ref. Doc. 64, p. 9.) The gear box lubrication issue was identified as an unresolved item pending BG&E establishing clear

acceptance criteria for the lubricant; determining the acceptability of the main gear box lubricant; and taking action to correct any unacceptable lubricant conditions identified. (OPC Ex. 8, Ref. Doc. 64, p. 9.)

It should further be borne in mind that the Inspection Report noted the existence of preventive maintenance procedures (PM's) as to the main gear box assembly and that the Company had already undertaken efforts to address the lubrication deficiencies identified through these procedures. (OPC Ex. 8, Ref. Doc. 64, p. 9.) Here, the NRC inspectors, even utilizing a higher standard of care, did not consider the lubrication of the main gear box assembly to be an issue of substantial safety significance. The NRC Inspection Report also concluded "that since all the bulletin valves were tested with full differential pressure across the valve, there is reasonable assurance that these valves can perform their safety function. Based on the review of the licensee's LERs and PM's, no MOV failures were observed during the past two years." (Id., p. 10.) It is submitted that the Commission should not hold the Company to a higher standard than that applied by the NRC.

A gear box assembly grease sampling program had been in existence at Calvert Cliffs for a number of years as a preventive maintenance program designed to identify degraded grease prior to its having an effect on valve operability. In early 1989 the Electric Power Research Institute (EPRI) issued a set of guidelines changing acceptance criteria. When the MOV gear box grease was sampled using the new criteria, many samples failed, necessitating relubrication. (Co. Ex. 15, p. 45.) In order to relubricate an assembly it is necessary for it to be disassembled, in which case an inspection is performed and any worn parts are replaced. It was these Company efforts, in part, which resulted in the large cost increase in the MOV program. (Co. Ex. 15, p. 45.) They took place in early 1989 at the beginning of the Unit 2 outage and began prior to the NRC inspection.

The Company performed maintenance during the test year on many more MOVs than the 12 Unit 1 Bulletin 85-03 valves which were the subject of the NRC

inspection and subsequent violation notice. The maintenance performed on the other Unit 1 valves included torque switch replacement, motor repairs, actuator repairs and relubrication. The original scope of work called for replacement of 62 torque switches on both Units 1 and 2, in response to a safety notification from the manufacturer. (Id.) The torque switch replacement also involved partial disassembly and, together with the grease sampling program, identified the need to relubricate, replace components, and overhaul some 90 valves on both Units 1 and 2. (OPC Ex. 8, Ref. Doc. 66.) The cost estimate for the increased scope of work was $1,500,000. (Id.) The MOV maintenance work performed during the test year for both units cost about $600,000. (T. 2294.)

In short, the dollars expended under the MOV cost estimate during the test period were not a result of deficient procedures. Rather, the Company had maintenance procedures in place, which it was utilizing, and when, in the course of following the procedures, adverse conditions were identified, additional corrective actions were implemented. This is nothing more, nor less, than executing standard maintenance practices. The dollars expended on this activity should be allowable for rate-making purposes.

Low Temperature Over-pressure Protection (LTOP):

Focusing on a March 6, 1990 NRC NOV on the subject, the Commission concluded that "BG&E failed to fulfill certain of its LTOP commitments to the NRC and failed to implement timely corrective action regarding its LTOP" and that the NRC documents "clearly indicate safety-related problems extending over a period of several years."

It also appears that the Commission based its conclusions, at least in part, on a lack of documentary support for the Company's position that LTOP was a generic industry concern. However, the NRC's Generic Letter, G.L. 88-11, issued July 12, 1988, is in itself evidence of a generic concern on the part of the NRC. This Generic Letter required all

licensees to perform a reanalysis to meet new NRC guidelines for calculating the effect of neutron radiation on reactor vessel materials. It applied to both Pressurized Water Reactor and Boiling Water Reactor licensees and required the response to include a plan and schedule for implementation in approximately three years. It further discussed the additional operating restrictions which the new methodology would introduce. G.L. 88-11 clearly resulted from the NRC's concern over the LTOP issue on an industry-wide basis. The generic nature of the LTOP problem was further noted by the NRC in Inspection Report 89-31/89-31, dated January 3, 1990 (OPC Ex. 8, Ref. Doc. 67, p. 2.)

> ...During the last three years ... the NRC issued new guidelines and requirements based on industry experience (Generic Letter 88-11), and the licensee took measures to respond to Generic Letter (GL) 88-11.

To the extent that the Commission's determination was grounded on a belief that LTOP was not a generic issue, it is submitted that the Commission should revisit the subject.

It is further submitted that the Commission's decision on LTOP holds the Company to an unreasonably high standard of performance by accepting the hindsight view of the NOV. As the Commission expressly recognized in its Order (p. 81), LTOP is designed to protect the reactor vessel from brittle fracture by preventing the reactor coolant system from exceeding certain pressure limits during low temperature operation. It is a complex regulatory issue. Since original implementation, a number of activities addressing LTOP have been ongoing at Calvert Cliffs which confirm that management was aware of existing problems and was taking what it considered to be appropriate action under the circumstances. It can be shown that, during the three years prior to the Oct./Nov. 1989 NRC inspection, BG&E developed revised Pressure-Temperature (P-T) curves to cover 10-12 effective full power years (EFPY) (early 1987), the NRC issued new LTOP guidelines and requirements (Generic Letter 88-11, issued July 12, 1988), and BG&E took action to respond to these requirements (Technical Specification Amendment - October 26, 1989).

The initial revised P-T curves were necessary because the existing curves were only valid until 10 EFPY -- a limit being approached by Unit 1. Although 10-40 EFPY curves already existed in the Technical Speci:.cations, they were much more restrictive for operating the plant. With the issuance of G.L. 88-11, another set of P-T curves needed to be developed and provided to the NRC. The 10-12 EFPY P-T curves were not needed, since new curves were now necessary in order to incorporate and reflect the LTOP standards presented in G.L. 88-11 and were intended to correct other known existing deficiencies.

Although without disputing NRC's NOV, the Company submits that its earlier actions should not be viewed by the Commission in the light of the NRC's 1989-1990 position because to do so holds BG&E to a standard of performance exceeding that of prudence. The NOV by itself cannot and should not be used as a basis for determining prudence. The actions the Company took were reasonable at the time and under the circumstances and there really has not been any showing to the contrary.

IV.

CONCLUSION

For the reasons stated in this Petition, the Commission should grant rehearing and modify its Order accordingly. If the Commission reconsiders any issue raised in this Petition, any adjustment to rates can be effected at the time the Commission orders the rate adjustment that will reflect the addition to rate base of Brandon Shores Unit No. 2, although accounting adjustments, such as any capitalization of interest on the deferred electric fuel balance can and should be effective with the date of the underlying rate order.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 16th day of January, 1991, copies of the foregoing Petition for Rehearing of Baltimore Gas and Electric Company were hand-delivered or mailed by first-class postage prepaid, to all parties to this proceeding.

Harvey J. Reed

Harvey J. Reed
Attorney for
Baltimore Gas and Electric Company

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APPENDIX I

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Commerce Commission On Its Own Motion -vs- Commonwealth Edison Company Reconciliation of revenues collected under fuel and gas adjustment charges with actual costs.	:	86-0511
	:	Consolidated
Illinois Commerce Commission On Its Own Motion -vs- Commonwealth Edison Company Reconciliation of revenues collected under fuel and gas adjustment charges with actual costs.	:	87-0123

ORDER

By the Commission:

On December 10, 1986, and March 18, 1987, the Commission entered Orders in Dockets Nos. 86-0511 and 87-0123, respectively, Commencing Reconciliation Proceedings, in accordance with the requirements of Section 9-220 of The Illinois Public Utilities Act, which directed Commonwealth Edison Company ("Edison" or "Respondent") to present evidence in these dockets at public hearings to show the reconciliation of revenues collected under Respondent's fuel adjustment clause ("FAC") with the actual cost of such fuel "prudently purchased" for the 12 month periods ending December 31, 1985 and December 31, 1986.

Notices of the filing of Respondent's testimony and exhibits were posted in Respondent's business offices and were published in newspapers having general circulation in Edison's electric service territories, in the manner prescribed by 83 Ill.Adm.Code 255 (formerly General Order 157) in compliance with the Orders of the Commission in this proceeding.

On January 9, 1987 in Docket No. 86-0511, Edison filed a Motion to Suspend Proceedings which the Commission granted on February 18, 1987. On April 1, 1987, the Commission, on its own

Edison's witness Scott testified that Edison had used proper care in taking care of the forced, unplanned outages that occurred. Mr. Scott gave three reasons in support of his statement. First, outages due to human error cannot be eliminated. Second, all work is supervised. Third, Edison has well-trained technicians on staff. The technicians must pass a screening test and go through 27-52 weeks of training. In addition, there is on-the-job training and continued annual training throughout the technician's career with Edison.

Staff witness Gould testified that Edison did not imprudently incur fuel costs as a result of the LaSalle outage. The outages, which occurred due to unexpected activities at LaSalle during 1985, were not unnecessarily extended and were not the result of management negligence. Staff did not investigate any other outages occurring during the reconciliation periods.

No other party presented a witness on this issue.

III. Prudent Operations at Nuclear Units

A. BPI Contentions

BPI generally contended that in Docket No. 84-0395 the Commission determined that prudency of nuclear plant operating performance is a relevant issue in a UFAC reconciliation proceeding. BPI alleged that the Commission ordered a $70 million refund in that docket due to the unreasonable replacement fuel costs incurred as a result of the poor performance of LaSalle 1. BPI maintained that in 1985 and 1986 Edison's nuclear plant operating performance was sub-par and plants were shut down due to imprudent operation and maintenance practice and procedures.

BPI reviewed the overall operating performance of Edison nuclear units, LaSalle 1 and 2 during the reconciliation periods. For example, LaSalle 1 operated at a 21.3% capacity in 1986, and LaSalle 2 at a 36.3% operating capacity in 1985. The overall operating capacity for the LaSalle units in 1985 and 1986 was 42%. BPI relied on the Nuclear Regulatory Commission's ("NRC's") Systematic Assessment of Licensee Performance Reports ("SALP Reports") regarding nuclear plant operations, maintenance, modification and surveillance activities at the LaSalle units in 1985 and 1986. Edison received a Grade 3 rating, which is the lowest rating given for these units. BPI concluded that these low ratings combined with low capacity factors are probative in showing imprudence.

BPI specifically reviewed the February 28 to July 20, 1985 outage at La Salle 2. This outage was due to extended maintenance, surveillance and environmental qualification ("EQ"). Citing the SALP 5 Report, BPI contended that there was a lack of early planning and scheduling of the outage and a lack of thoroughness and depth in correcting violations. BPI cited the NRC Task Force conclusion that the operational problems at LaSalle reflected poor management oversight and were more serious than at other similar late model boiling water reactors ("BWRs"). Also, BPI claimed that Edison's response to a subsequent one-month outage at LaSalle 2 due to EQ requirements was inadequate.

BPI relied on the decision in Pennsylvania Public Utility Commission v. Philadelphia Electric Company, 561 A.2d 1224 (Pa. 1989), wherein the Pennsylvania Supreme Court concluded that where there is a lack of sufficient maintenance policy and a failure to adhere to NRC requirements, the replacement fuel costs cannot be passed on to customers.

BPI proposed that a reasonable 60% capacity factor be established and refunds ordered by taking the difference between the 60% capacity factor and the actual capacity factors for LaSalle 1 in 1985 and 1986 of 50.9% and 21.3%, respectively, and LaSalle 2 for 1986 of 36.3%. As an alternative, BPI proposed a refund based upon the 42% actual overall capacity factor for the LaSalle units during the reconciliation periods. BPI also proposed another alternative using a 60% baseline capacity factor and comparing it to the actual overall performance of all Edison nuclear units in 1985 of 53.2% and 56.6% in 1986. BPI argued that, at the least, the Commission should rely upon industry-wide averages of 58.0% in 1985 and 56.9% in 1986.

BPI specifically criticized Edison's handling of the 335 day outage at LaSalle 1 occurring between November, 1985 and October, 1986. BPI alleged that this outage was extended from Edison's projected five months to eleven months due to insufficient staff and management failures. BPI claimed that Mr. Calle acknowledged that Edison was aware of certain problems involving Limitorque motors and snubber failures in planning for the refueling outage (Tr. 1449-50).

BPI noted some of the specific outages contained on BPI Cross Exhibits 2 and 3. As an example, BPI pointed to the LaSalle 1 outage of eleven days between March 22 and April 2, 1985 which resulted in $6,697,791 in additional fuel costs. This outage was due to misunderstood communications that triggered a pressure spike shutting the unit down. Some other examples of shutdowns due to personnel errors occurred at Dresden 3, Byron 1 and Zion 2. A Zion

2 shutdown occurred when a worker failed to follow the correct valving sequence and this resulted in additional fuel costs of $1 million. Edison established a new double verification check after this outage. Byron 1 was placed in-service on April 1, 1985. Its first year operating capacity was 40%. BPI alleged that Edison received "favorable accounting treatment" from the Commission in Docket No. 85-0092, thereby forcing consumers to pay for the plant in base rates, while it operated at a low 40% capacity factor. BPI also generally contended that the high number of recurring problems and personnel errors resulted in unnecessary scrams and demonstrated Edison's imprudence.

In addition to the Philadelphia Electric decision previously cited, BPI reviewed the decisions in Boston Edison Company v Dept. of Public Utilities, 471 N.E.2d 54 (Mass. 1984), Virginia Electric & Power Company v. Division of Consumer Counsel, 275 S.E.2d 697 (Va. 1980) and Baltimore Gas & Electric v. Public Service Commission 501 A. 2d 1307 (Md. 1986) and concluded that where imprudence is shown, additional fuel costs will not be passed on to customers. BPI deduced that Edison had failed to meet its burden of proving reasonableness and prudency with respect to the outages set forth on BPI Cross Exhibits 2 and 3 and the replacement fuel cost amounts should be refunded to customers.

BPI criticized Staff for its superficial review of the LaSalle 1 outage and lack of review of other outages during the reconciliation period.

BPI concluded that Edison's low capacity factors and number of forced outages described in BPI Cross Exhibits 2 and 3 provide prima facie evidence of Edison imprudency. The SALP Reports rebut Edison's claim of prudency.

B. Edison Contentions

Edison generally contended that the Commission should apply a "reasonable man" standard as previously used by the Commission in Docket No. 84-0395 in determining prudency. In reviewing the operation of Edison's nuclear plants, Edison maintained that the test is whether reasonable people would have acted differently than Edison personnel in planning and managing the outages during the reconciliation periods.

Edison disputed the use of the SALP Reports. Edison contended that the SALP Reports deal with "safety performance" and are not sufficient, in and of themselves, to establish imprudence. Edison urged the Commission to analyze the particular facts and circumstances of each outage. Edison alleged that while a SALP

Report Rating 3 is low, it is still satisfactory or acceptable. Edison's review of SALP Reports 5 and 6 showed that regarding LaSalle Station, Edison received 17 Category 1 or 2 ratings and only 4 Category 3 low ratings.

Edison contended that its overall operation of its nuclear plants in 1985 and 1986 was reasonable. Edison specifically discussed the LaSalle 1 refueling outage. Edison maintained that the rewiring of the Limitorque motor operator and modifying the wire splices was not known or expected to be done during the planning of the Edison refueling outage. Edison contended that it did not know that it would have to test and service all 1,238 snubbers. In 1981, the snubbers were tested and found to be working properly and so Edison planned only a sample testing of 55 snubbers during the outage. In June, 1986 at LaSalle 2, the SOR switches did not work properly and the unit shut down. Edison maintains that when the SOR switches were installed and tested, no problems occurred. After the switch failure, testing revealed that there was setpoint drift requiring each differential pressure switch to be adjusted. Edison claimed that the SOR switch work on LaSalle 2 extended the LaSalle 1 outage because Edison personnel had to be switched from LaSalle 1 to LaSalle 2 to do the switch work.

Edison discussed the unplanned concurrent outages at both LaSalle units. Concurrent outages occurred twice, from October 21, 1985 to December 23, 1985 due to problems with the Limitorque motor operator and splice work, and from June 1 to August 8, 1986 due to work on SOR switches. Edison specifically denied that there was a diversion of personnel from LaSalle to Byron. Edison contended that there are only so many qualified personnel to do the work.

Edison also specifically discussed other outages. At LaSalle 2, the surveillance and EQ outages between February 28 and July 2, 1985 was an ordinarily planned outage which, in part, was for required surveillance and EQ work which had to be completed by November 30, 1985. From October 21 through November 23, 1985, LaSalle 2 was shut down for Limitorque motor operator and splice work. The Dresden 3 pipe replacement and refueling project took about ten months, between October 28, 1985 and September 1, 1986, which Edison maintained is about the industry average. Edison described the Byron 1 shutdowns occurring between April and September, 1985 due to start-up testing and the October 25 to December 18, 1985 shutdown for maintenance after the unit began commercial operation on September 16, 1985. These outages led to a 40% operating capacity for Byron 1 in 1985. However, Edison asserted that due to 1985 surveillance work, the 1986 capacity

factor for Byron 1 was 75.4%. He maintained that simply because Edison changed its procedure after the Zion 2 outage of September 20-22, 1986, it did not mean the procedure was deficient. Based upon Mr. Scott's investigation of outages in 1985 and 1986, he concluded that outages due to personnel errors and equipment failure were not due to lack of care by Edison. He contended that the test is whether Edison took reasonable steps to safeguard against the error.

Edison argued that it is unfair to set performance standards. Edison pointed to the fact that the Commission failed to set a performance standard for the Clinton plant in Illinois Power's rate case, Docket No. 89-0276, Order dated June 6, 1990. Edison contended that Edison's capacity factors for 1985 and 1986 were roughly comparable to industry averages and regulation by capacity factors is unfair because it fails to reward Edison for nuclear units operating above the industry average.

Edison sought to distinguish the cases cited by BPI in these dockets. Edison contended that there must be more than a violation of NRC procedure to support imprudence, citing the Baltimore Gas and Electric case.

Edison maintained that general comments from SALP reports should not take the place of examining specific facts and circumstances of each outage. Mr. Scott discussed Edison's procedures and safeguards, and there is no showing that these were imprudent.

C. Staff Conclusion

As previously mentioned, Mr. Gould only investigated the eleven month LaSalle 1 outage. He concluded that Edison did not incur any fuel costs imprudently during the reconciliation periods.

D. Commission Analysis and Conclusions

As the Respondent in these proceedings, Edison has the burden of showing it operated its nuclear units prudently in 1985 and 1986. To meet this burden, Edison presented the testimony of two witnesses, Messrs. Galle and Scott. Mr. Galle's testimony concentrated on the eleven-month outage at LaSalle 1, while Mr. Scott generally described the bases for twenty-one outages at various Edison nuclear units during 1985 and 1986. Staff witness Gould testified about the LaSalle 1 outage, although there is ample evidence to indicate that the Staff had requested and received from Edison substantial information regarding all outages occurring

during the reconciliation periods prior to his testimony being filed. Mr. Gould testified that he found no imprudence on Edison's part for the LaSalle 1 outage. No other party presented testimony regarding outages in 1985 and 1986. Thus, the Commission may properly conclude that Edison made a prima facie showing that it acted prudently regarding the management, operation and maintenance of its nuclear generating units in 1985 and 1986.

This Commission continues to believe that the term "prudent" has the same meaning as it did in Docket No. 84-0395. This Commission adopted the following language used by the Pennsylvania Public Utilities Commission in Re Salem Nuclear Generating Station, 70 P.U.R. 4th 568, 574 (October 24, 1985), wherein the Commission stated:

> Prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made. In determining whether a judgment was prudently made, only those facts available at the time judgment was exercised can be considered. Hindsight review is impermissible.

The Commission agrees with Edison that the review of Edison's nuclear units during these reconciliation periods must show that reasonable people would have acted differently than Edison's management in planning and managing outages during 1985 and 1986.

The Commission also agrees with the Hearing Examiners that it is appropriate to take administrative notice of the SALP Reports, BPI Cross Exhibits 5, 6, 7 and 8. After reviewing the SALP Reports it is clear that their primary thrust is directed toward the "safety performance" of Edison's nuclear units. The SALP Reports are useful in three ways to the Commission: 1) in a few instances during the reconciliation periods, specific outages are discussed; 2) trends toward improving or worsening safety performance at Edison nuclear units generally may be established; and 3) a general perception may be gained regarding Edison's nuclear unit operations and its regard for safety.

The SALP Reports, however, by themselves, cannot establish whether Edison operated its nuclear units individually, or collectively, in an imprudent manner. The Commission is not pleased that Edison received Category 3 ratings from the NRC in the categories of plant operations, maintenance, modification and

surveillance during 1985 and 1986, which is the lowest rating given by the NRC. Obviously, Edison must improve the operation and maintenance of its nuclear plants.

The basic question presented in the use of the SALP Reports, however, is whether the SALP Reports indicate that Edison operated its nuclear units imprudently. A Category 3 rating is the lowest rating given by the NRC. In defining the three performance categories, the SALP Board defined Category 3 as follows:

> Category 3: Both NRC and licensee attention should be increased. Licensee management attention or involvement is acceptable and considers nuclear safety, but weaknesses are evident; licensee resources appear to be strained or not effectively used so that minimally satisfactory performance with respect to operational safety or construction is being achieved. (BPI Cross Exhibit 4, p.3)

BPI has cited extensively from SALP Reports 5 and 6. SALP Report 5 generally stated that Edison performed inadequate testing for operability of equipment after maintenance and modification. SALP Report 5 discussed the lack of early planning and scheduling of the LaSalle 2 outage which resulted in extensive delay in completion of the outage. SALP Report 6 stated that Edison has not sufficiently planned ahead for the outage and Edison lacked sufficient manpower for the outage. The foregoing comments cannot, however, be squared with NRC statements in all four SALP Reports that found Edison's overall conduct acceptable. While the Commission should take administrative notice of these NRC reports, they cannot be given much evidentiary weight without appropriate testimony and cross-examination. If the SALP Board believed that Edison's operations and maintenance of its nuclear units was so bad, then how could the SALP Board find Edison's conduct acceptable? There seems to be a built-in inconsistency in the SALP Reports. Under such circumstances, the use of the SALP Reports for reconciliation purposes is limited to taking administrative notice of such reports and cannot be used as an evidentiary basis for findings of imprudency by Edison. The Commission cannot base imprudency solely on the SALP Reports. The SALP Reports do not indicate that Category 3 ratings are the worst ratings, or that such ratings show imprudency of nuclear plant operation.

The relevance of capacity factors of Edison nuclear units, either specifically or for all of the nuclear units, is also limited. The Commission Order in Docket No. 85-0517 stated the following regarding operating standards and capacity factors:

"This docket is not the proper forum to adopt operating standards and appropriate capacity factors for nuclear plants. If BPI is interested in doing so, it should request a general rulemaking on the specific subject." (Page 2 of Order).

BPI seeks to have the Commission adopt a 60% operating capacity factor for Edison. In Docket No. 84-0395, the Commission established no such operating factor for LaSalle 1. That Docket compared Edison's actual operating capacity in 1983 of 17.7% with Edison's own projected operating capacity factor of 60%. Under the specific circumstances relating to LaSalle 1 in 1983, the Commission determined that a reasonable person would have expected LaSalle 1 to operate at a 60% capacity factor. It should be obvious that the Commission will review the operating capacity of each Edison nuclear unit and Edison's overall performance in each reconciliation period to determine if Edison acted imprudently. This requires a detailed examination which would, as examples, look at LaSalle's operating capacity of 21.3% in 1986, LaSalle Nuclear station's average operating capacity in 1985 and 1986 of 42% and Edison's overall performance of 53.2% in 1985. BPI's assertion that, based upon Edison's experience operating nuclear plants, its operating capacity should be higher than the industry-average is not probative of a conclusion that Edison has operated and managed its nuclear units imprudently. The Commission Order in the Illinois Power Company rate case, Docket No. 89-0276 dated June 6, 1990, noted the following: "The determination of performance standards for nuclear generating units is an important question which should be addressed in the context of its statewide implications." The Commission went on to direct Staff to examine the propriety of such an inquiry. (See pages 173-4 of Order). The specific instances relating to each outage must be reviewed.

The 335 day outage of LaSalle 1 between November, 1985 and October, 1986 due to its length alone merits special examination. This outage was one that was planned and ordinarily would take only five or six months, not the eleven months it actually took. An examination of the record indicates that this outage was extended for four principal reasons: 1) there was an insufficient number of Edison personnel assigned to the outage; 2) the Limitorque motor operators had to be rewired; 3) all snubbers had to be replaced; 4) SOR switches had to be reset. The positions of BPI and Edison regarding this extended outage have been fully explained earlier in this Order and need not be reiterated. While there is some question whether Edison had committed enough personnel to the LaSalle 1 outage, the Commission is satisfied that Edison did not knowingly provide an insufficient number of personnel to deal with the initial LaSalle 1 refueling outage. There has been no evidence presented that Edison should have assigned more personnel at the

time it planned the outage, or could have reasonably expected the need for additional personnel, or that additional personnel was available. The Commission is also satisfied that Edison could not have reasonably anticipated the Limitorque motor operator and splice work and the testing of 1,238 snubbers and the work needed to reset the SOR switches. There is no evidence of imprudency regarding the LaSalle 1 outage.

Other specific outage instances relating to Edison's nuclear units in 1985 and 1986 may be reviewed in BPI Cross Exhibits 2 and 3 in these dockets and the testimony of Edison witnesses Galle and Scott. Mr. Scott, in particular, commented on twenty-one individual outages occurring in the reconciliation periods. After reviewing the BPI Cross Exhibits 2 and 3 in each docket and Mr. Scott's summary of each outage, it appears that the overwhelming number of outages occurred due to human error. As noted in the Docket No. 84-0395 Order, page 19: "Where human beings are involved, no safeguards and procedures are outage-proof." Edison generally described it training procedures and, in many outage instances, described how frequently the same function has been performed which caused an outage, without error. There is no evidence to indicate that Edison acted imprudently regarding these outages caused by human error. There is also no evidence presented which shows what steps Edison could have prudently and reasonably taken to avoid those outages caused by equipment failure.

BPI Cross Exhibit 4, SALP Report 5, generally discusses personnel error which, due to their high number, were "considered excessive." Even this kind of statement cannot be considered conclusive on the subject of personnel errors. The record shows twenty-one outages in 1985 and 1986, with a total of approximately fifteen caused by personnel errors. However, there has been no proof provided in the record stating that this number of outages is excessive given the number of Edison nuclear units in operation during the reconciliation periods.

Based upon the foregoing, the Commission must conclude that there is a lack of sufficient evidence to overcome Edison's *prima facie* showing that it operated its nuclear units prudently during the reconciliation periods, 1985 and 1986.

IV. Bill as Dispatch

A. Introduction

Commonwealth Edison attributes one "cost", an incremental cost, to its western coal in establishing the order in which it dispatches its generating plants but attributes a greater "cost" to