CEPFOD Statement No. SR 1

R-943271 Hbg JK
5/26/95

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Regarding

PENNSYLVANIA POWER & LIGHT COMPANY

Docket Number R-00943271

Surrebuttal Testimony Of

Steven Andersen

On Behalf of

Central Eastern Pennsylvania Fuel Oil Dealers

Economic & Policy Analysis, Inc.
13300 Council Bluff Drive
Austin, Texas 78727

May 19, 1995

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I. Introduction and Summary

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven Andersen. My business address is 13300 Council Bluff Drive, Austin, Texas 78727.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS CASE?

A. Yes. I filed direct testimony regarding cost allocation and rate design issues on behalf of the Central Eastern Pennsylvania Fuel Oil Dealers (CEPFOD) on April 12, 1995. This testimony has been marked as CEPFOD Statement 1.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. My purpose is to respond to portions of the rebuttal testimony filed on behalf of PP&L by Mr. Slivka, Mr. Kleha, and Mr. Kasper. I also respond to testimony filed by Mr. Knecht (SBA) regarding the classification and allocation of distribution plant and expense.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING PP&L'S DEFENSE OF THE COMPANY'S RTS MARKETING PROGRAM.

A. I agree with Mr. Slivca that it is important to evaluate PP&L studies and the prudence of PP&L's promotion of RTS service within the context of a 1987-1991 time frame. My analysis was based upon reviewing information known to PP&L during that time period. Instead, the Company defends the promotion of RTS service on the ground that a hypothetical future fix for the RTS peaking problem may exist, and that implementation of this hypothetical fix might reduce RTS subsidies below their current levels. Even if these speculative assertions prove correct, they provide no basis for shifting the burden of current the $26.5 million RTS subsidy to other rate classes. My specific conclusions regarding the rebuttal testimony filed by PP&L are that:

1. Mr. Slivca's claim that RTS service is not responsible for the shift of system peak from the morning to the evening is inconsistent with actual PP&L experience.
2. Mr. Kasper claim that RTS service provides a load management benefit and a financial benefit to other rate classes is unsupported, and inconsistent with current and past studies prepared by PP&L.

3. Mr. Kasper's assertion that the rate for RTS service is compensatory and that RTS revenues provide a contribution to the recovery of fixed costs is erroneous, and inconsistent with PP&L analyses of RTS costs and revenues.
4. Mr. Slivca and Mr. Kasper demonstrate that RTS service has been less of a DSM and financial failure than would have been the case if the Company had achieved 1987 marketing goals. However, they do not demonstrate that PP&L's efforts to promote RTS service were prudent.

Q. DOES THE REBUTTAL TESTIMONY FILED BY PP&L CAUSE YOU TO CHANGE YOUR RECOMMENDATION THAT THE COST OF THE RTS SUBSIDY BE ABSORBED BY PP&L?

A. No. PP&L's defense of the Company's promotion of RTS service consists of the assertion that a future solution to the RTS peaking problem may be found. The Company's defense is not a valid justification for imposing the current cost of RTS subsidies on other rate classes.

II. RTS Costs and Benefits

Q. MR. SLIVCA ASSERTS THAT THE RTS PEAKING PROBLEM ANTICIPATED BY PP&L IN 1987 WAS PREDICATED ON THE ASSUMPTION OF AN AGGRESSIVE RTS MARKETING PROGRAM. HE CLAIMS THAT A PEAKING PROBLEM DID NOT MATERIALIZE BECAUSE PP&L CURTAILED THE PROMOTION OF RTS IN 1990. DO YOU AGREE?

A. I agree that PP&L failed to achieve the Company's 1987 RTS marketing goal of serving 52,000 thermal storage customers by 1995, but I have seen no evidence that demonstrates that this failure was the result of a change in PP&L policy. A more logical inference is that PP&L was committed to the promotion of RTS, but that the Company failed in its efforts due to a steady erosion in the competitiveness of PP&L's RTS rate relative to alternative heating sources. The fact that PP&L consistently spent over $2,000 <u>per customer</u> between 1987 and 1992 in order to attract customers to RTS service demonstrates aggressive promotion. Despite the fact that marketing goals were not achieved, the number of RTS customers on the system more than doubled between 1988 and 1995 as a result of PP&L's promotional efforts. PP&L's management of the RTS program was not prudent.

I also disagree with Mr. Slivca regarding his claim that an RTS peaking problem did not develop. The shift of PP&L's system peak from the morning to the evening hours can be largely explained by the promotion of RTS service. PP&L's estimate of the RTS class contribution to test year system peak is 258 MW (OTS-RS-9D). Peak demand per RTS customer is approximately six times the RS class average coincident peak per customer. As indicated in Table 2 (CEPFOD Statement 1, page 15), the difference between the 1993 morning peak and the 1994 evening peak (274 MW) is not appreciably different from PP&L's estimate of the RTS class contribution to system peak. Adjustment of the 1993 peak for customer growth would further narrow the difference between morning and evening peaks. Therefore it is reasonable to conclude that the promotion of RTS service accounts for a large part if not all of the shift of PP&L's peak demand from the morning to the evening hours. At pages 2 and 3 of his rebuttal testimony, Mr. Slivca attributes the shift of PP&L's peak from the morning to the evening hours to changes in the composition and shape of the Company's load, and unpredictable weather conditions. He provides no empirical support for these assertions, and no alternative explanation of the rather obvious correlation between the timing of RTS and system peaks.

Q. IS MR. SLIVCA'S ANALYSIS OF THE CONSEQUENCES OF SHIFTING CUSTOMERS FROM RS TO RTS SERVICE COMPLETE?

A. No. Mr. Slivca's defense of PP&L's promotion of RTS service is defective because it completely disregards the increase in demand associated with shifting customers to a thermal storage system, the higher distribution costs that have resulted from the promotion of RTS service, and the loss of residential load diversity that has resulted from shifting customers from RS to RTS service. These problems are discussed at pages 14 and 15 of my direct testimony, but are not addressed in PP&L's rebuttal testimony.

Q. DOES MR. KASPER'S CLAIM THAT PP&L PLANS TO UNDERTAKE A PILOT PROGRAM IN AN ATTEMPT TO SOLVE THE RTS PEAKING PROBLEM JUSTIFY SHIFTING THE BURDEN OF RTS SUBSIDIES TO OTHER RATE CLASSES?

A. No. As discussed at page 17 of my direct testimony, PP&L explored load management solutions to the RTS peaking problem in studies prepared in 1987 and 1991. Those studies concluded that a viable solution did not exist. Even if PP&L's "pilot program" is successful and the retrofit of existing RTS installations is workable and cost effective, only part of the RTS revenue deficiency would be eliminated. The Company and not its ratepayers should bear the cost of RTS subsidies until the benefits of further management of RTS loads has been demonstrated. Speculation about the future does not eliminate the current RTS subsidy, and it does not rebut my conclusion that past PP&L efforts to promote RTS service were imprudent.

Q. AT PAGE 11 OF HIS REBUTTAL, MR. KASPER ASSERTS THAT THE TREND TOWARD EVENING PEAKS "WILL REDUCE THE BENEFITS OF RTS UNLESS CONTROL DEVICES ARE PLACED ON THE CUSTOMERS' FACILITIES." DO YOU AGREE?

A. No. Mr. Kasper's testimony implies that RTS service has benefitted the system. In fact, RTS service has increased the coincident and non-coincident peaks of customers that have installed thermal storage, and has imposed a net additional cost on the system. PP&L has not demonstrated any RTS load management benefits. The Company's best case scenario is that RTS service has "little, if any, overall effect on the Company's peak day requirements" (Slivca, rebuttal page 9), and even this modest claim misrepresents the actual impact of RTS loads on system peak. Furthermore, Mr. Kasper states that control devices will be installed and tested for new thermal storage customers. The Company has not demonstrated that retrofits for existing customers will be possible if the pilot program is successful. Absent such a retrofit, the RTS subsidy will continue throughout the remaining life of existing RTS installations.

Q. AT PAGE 11 OF HIS REBUTTAL TESTIMONY MR. KASPER CLAIMS THAT RTS SERVICE BENEFITS OTHER CUSTOMERS BECAUSE IT PROVIDES A "CONTRIBUTION TO THE COMPANY'S FIXED COSTS." DO YOU AGREE?

A. No. The claim that RTS contributes to the recovery of fixed costs is false. The incremental revenue derived from RTS service is the difference between RTS revenues and the revenues that RTS customers would have provided had they opted for a conventional heating system and taken service under the RS rate. As discussed at pages 3 and 8 of my direct testimony (see also Kasper rebuttal exhibit OGK-7, CEPFOD response to question 18) incremental RTS revenues are not sufficient to even recover incremental energy costs. As a result, the service imposes a net cost on other classes even if costs and revenues are measured on an incremental basis rather than a more conventional comparison of revenues with embedded cost. Mr. Kasper's comparison of **average** RTS revenues ($.054 per kWh at page 20) with average and incremental energy cost ($.018 to $.022 per kWh at page 21) is deceptive because it assumes that an RTS customer's total usage would be **zero** if the customer had installed a conventional heating system. The framework proposed by Mr. Kasper is grossly inconsistent with earlier incremental analyses prepared by PP&L.[1]

Q. DO STUDIES PREPARED BY PP&L CONFIRM YOUR ASSERTION THAT RTS IS A SUBSIDIZED SERVICE?

A. Yes. The cost of service study filed by Mr. Kleha demonstrates that current RTS revenues cover only one half of the cost of providing service, and cost benefit analyses prepared by PP&L demonstrate that RTS service imposes a net cost on both other ratepayers and society. At page 40 of his rebuttal testimony Mr. Kasper relies on cost benefit analyses to defend the promotional industrial rates offered by PP&L. The absence of references to the results of cost-benefit studies in his rebuttal testimony regarding RTS is noteworthy.

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[1] See for example CEPFOD Exhibits 8, 13, and 16.

Q. MR. KASPER STATES THAT "IMPROVED LOAD CONTROL STEPS" ARE EXPECTED TO ELIMINATE THE "NEGATIVE RETURNS" SHOWN FOR RTS SERVICE. WHAT IS THE SIGNIFICANCE OF THIS STATEMENT?

A. The claim that the return for RTS might be positive if the RTS peaking problem is solved assumes (1) that the pilot study planned by PP&L will be a technological success, (2) that the benefits of further load management will exceed the cost, and (3) that RTS retrofit will also be cost effective. Even then, Mr. Kasper's claim that it may be possible to eliminate <u>negative</u> returns does not imply that the return for RTS would be equal to the RS or system average return on rate base if a load management retrofit turns out to be cost effective. Because all RTS usage is priced at a level "substantially lower than rates available under Rate Schedule RS" (Kasper, rebuttal page 24), it is likely that the class will remain subsidized even if PP&L is able remedy the RTS peaking problem through further load management.

Q. MR. KASPER DEFENDS PP&L PROMOTION OF RTS SERVICE AS A LOAD MANAGEMENT RATHER THAN A MARKETING PROGRAM. IS HIS DEFENSE PERSUASIVE?

A. No. At page 14 Mr. Kasper states that RTS met several criteria that PP&L used to screen load management programs:

1. an ability to shift demand from peak to off-peak periods;
2. a large potential market;
3. no need for large capital investments; and
4. a long expected life.

By 1987 PP&L knew that RTS was not an effective program for managing peak demand. Regarding PP&L's second criterion, a large potential market existed for RTS only because the RTS rate was set substantially below cost, and the price paid for all electricity used by an RTS customer was deeply discounted. With respect to item 3, Mr. Kasper states that the required investment was "largely incremental and directly proportionate to the number of participants", and that the cost of this investment was "shared between the company and the participants." (page 15) This statement provides no indication of the magnitude of required investment, nor does it imply that this investment was not large. Cumulative RTS promotional costs alone exceed $24 million, and customers were required to make a substantial additional investment in their heating systems in order to qualify for the rate. PP&L acknowledges that further investment in load management is required if any DSM benefit is to be realized from RTS. The fact that a customers heating system had a long physical life (item 4) was a detriment rather than a benefit because it implied a long period during which RTS subsidies would be required in order to shelter customers from the consequences of responding to PP&L's marketing program.

Q. MR. KASPER INDICATES THAT YOUR TESTIMONY IS IRRELEVANT TO THE "JUSTNESS AND REASONABLENESS OF RATE SCHEDULE RTS IN 1995 AND GOING FORWARD" BECAUSE IT RELIES ON OLD PP&L STUDIES. IS THIS ASSERTION CORRECT?

A. No. The central RTS issues in this case are (1) the prudence of PP&L's efforts to promote RTS service, (2) the extent to which the RTS subsidy should be reduced, and (3) whether PP&L should be permitted to recover the remaining RTS revenue deficiency from other rate classes. By proposing to freeze access to the RTS rate, PP&L has conceded that RTS should not be offered to new customers. Although PP&L has known that access to the RTS rate should have been closed for almost a decade, the Company continued to offer and promote RTS service. The fact that PP&L continued to promote RTS long after the Company knew that the service was a DSM failure has direct bearing on the disposition of RTS subsidies. Because PP&L's promotion of RTS service was unreasonable, the RTS subsidy should be no more recoverable from other rate classes than would the costs of a supply side investment found to be imprudent.

III. Cost allocation

A. Distribution Plant and Expense

Q. AT PAGE 20 OF HIS REBUTTAL TESTIMONY MR. KLEHA STATES THAT YOU SUPPORT THE USE OF A ZERO INTERCEPT METHOD. IS HE CORRECT?

A. No. I reject both the zero intercept and the minimum size variants of the minimum system approach to classifying distribution poles and lines as a waste of time. For the reasons discussed at pages 28 through 33 of my direct testimony, I recommend that the Commission find that:

1. a minimum system analysis is highly subjective, and produces an arbitrary classification of plant;
2. the hypothetical cost of a minimum system depends on customer density rather than customer count;
3. the facilities actually installed by PP&L are a poor proxy for minimum investment because they are based on expected usage; and
4. the Company's allocation of demand related distribution costs is defective because it fails to account for the load carrying capability of the minimum size plant that PP&L currently installs.

The third and fourth defects could be remedied by replacing PP&L's minimum size approach with a zero intercept analysis of minimum system costs. However, regardless of the method used to quantify minimum system costs, the classification of these costs as customer related is conceptually defective.

Q. AT PAGE 22, MR. KLEHA STATES THAT A ZERO INTERCEPT METHOD IS "INHERENTLY ARBITRARY." DO YOU AGREE?

A. Yes, but it is no more arbitrary than Mr. Kleha's assumption that PP&L would install the same minimum sized plant even if a customer were expected to impose no demands on the system, or his disregard for the load carrying capability of the plant that PP&L designates as minimum sized.

Q. AT PAGE 20 OF HIS REBUTTAL, MR. KLEHA REFERENCES THE NARUC COST ALLOCATION MANUAL AS SUPPORT FOR THE COMPANY'S CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT. IS THE MANUAL ACTUALLY SUPPORTIVE OF THE COMPANY'S ANALYSIS?

A. No. The authors of the Manual do appear to accept the treatment of a portion of distribution plant as customer related. However, the following discussion of the minimum size approach proposed by PP&L appears at page 95 of the Manual:

> Costs analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution is used to classify distribution plant. **When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load carrying capability, which can be viewed as a demand-related cost. (emphasis added)**

Because Mr. Kleha fails to account for the load carrying capability of currently installed minimum sized plant, adoption of PP&L's treatment of distribution plant results in a systematic over-allocation of costs to small customers. A zero intercept approach is, according to Mr. Kleha, arbitrary and too complex. From the perspective of cost causation, both methods are conceptually defective. A more reasonable approach is to recognize that poles, lines, conduit, conductor, and transformers are installed to meet expected demand and sized accordingly, and to treat all associated investment as demand related.

Q. MR. KNECHT STATES THAT PP&L'S MINIMUM SYSTEM ANALYSIS FOLLOWS THE "DICTATES OF THE NARUC MANUAL" (OSBA Statement R1, page 8). IS THIS STATEMENT CORRECT?

A. No. The preface of the NARUC Manual states that the authors' intent was "to be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons." (page ii) As discussed above, the Manual describes both the zero intercept and minimum size variants of the minimum system approach, but certainly does not "dictate" the use of either approach or the classification of a portion of poles, lines, or transformers as customer related.

Q. DOES MR. KNECHT DISPUTE THE EXISTENCE OF A DOUBLE COUNTING PROBLEM WITH RESPECT TO PP&L'S ALLOCATION OF DISTRIBUTION PLANT?

A. No. He acknowledges that the problem exists, but concludes that it would be difficult and time consuming to remedy.

Q. DOES MR. KNECHT OFFER ANY JUSTIFICATION FOR THE CLASSIFICATION OF A SHARE OF POLES, LINES, AND TRANSFORMERS AS CUSTOMER RELATED?

A. No. He asserts that the addition of "a new residential development" without any accompanying increase in demand would necessitate the addition of poles, lines, and transformers. He then asserts that "a minimum system analysis attempts to measure this impact". The "impact" that Mr. Knecht proposes to measure is, like the minimum system concept, purely hypothetical. The actual investment that will be made as a result of adding a new customer or group of customers will depend primarily on customer location, customer demand, and the capacity and configuration of currently installed plant.

B. Administrative Overheads

Q. MR. KLEHA ASSERTS THAT THE ALLOCATION OF ALL A&G EXPENSES AND INVESTMENT IN INTANGIBLE PLANT BASED ON PAYROLL IS SUPPORTED BY THE NARUC MANUAL, AND REASONABLE BECAUSE IT PROVIDES A "COMPREHENSIVE RATIO OF A UTILITY'S PRODUCTION, TRANSMISSION, DISTRIBUTION AND OTHER FUNCTIONAL LABOR COSTS". (PAGE 26) DO YOU AGREE?

A. No. Mr. Kleha does not address the issues and analyses discussed at pages 25 and 33 through 36 of my direct testimony. Many of the expense items at issue and all of PP&L's investment in intangible plant are PTD plant rather than labor related. Mr. Kleha's claim that he has used a comprehensive measure of class responsibility for payroll expense does not demonstrate that his allocation of A&G expense or his allocation of intangible plant captures cost causation. As demonstrated in Table 7 (CEPFOD Statement 1, page 34), the allocation proposed by PP&L is systematically biased against small customers, and should be rejected. The allocation of overheads based on class responsibility for direct PTDC non-fuel revenue requirement that I recommend better reflects the composition and causation of overheads.

C. Conclusion

Q. MR. KLEHA ASSERTS THAT THE COST ALLOCATION CHANGES THAT YOU RECOMMEND ARE NOT SUPPORTED BY EMPIRICAL EVIDENCE, AND ARE MERELY THE RESULT OF SUBSTITUTING YOUR JUDGEMENT FOR THE COMPANY'S. DO YOU AGREE?

A. No. Mr. Kleha does not define "empirical" evidence. However, regarding the distribution plant issue, I would observe that:

1. Customers apply for electric service because they have a need for electricity.
2. PP&L offers electric service because it expects customers to buy electricity.
3. The distribution plant that must be installed in order to sell electricity to customers that join the system depends primarily on expected demand.

In my opinion, these facts conform with the "common sense perspective" advocated by Mr. Knecht (OSBA Statement R1, page 10). In contrast, Mr. Kleha proposes to allocate 64 percent of secondary distribution investment and expense based on the hypothetical cost of connecting to the system a customer with no need for electricity. He bases this recommendation on the premise that PP&L would install the same minimum sized plant that the Company currently installs in order to serve actual residential loads. From an empirical perspective, this claim is implausible.

With respect to the allocation of overheads, I have examined the actual composition of these costs and found only a small share to be actually related to payroll. Mr. Kleha has not rebutted my empirical analysis. Instead, he proposes that the Commission ignore the actual composition and causation of costs, and allocate these items of expense and plant based on judgement because a payroll allocator is an "easily calculated .... generally accepted proxy" (page 26) for actual cost causation.

IV. Residential (RS) Rate Design

Q. AT PAGE 6 OF HIS REBUTTAL, MR. KASPER ASSERTS THAT YOU HAVE RECOMMENDED NO INCREASE IN THE CURRENT RS CUSTOMER CHARGE. IS THIS CORRECT?

A. No. As stated at page 43 of my direct testimony, assuming that PP&L is awarded the full RS revenue increase requested, I recommend that the RS customer charge be increased from $4.80 to $5.80 per month. Such an increase would "would permit PP&L to more than recover out-of-pocket customer costs, preserve existing incentives to conserve, and provide a more reasonable sharing of the burden of a rate increase among RS customers". The Commission should, for the reasons discussed at pages 41 through 43 of my direct testimony, reject PP&L's expansive definition of RS "customer" costs and the Company's proposed 50 percent increase in the RS customer charge.

Q. AT PAGES 8 AND 9 OF HIS REBUTTAL, MR. KASPER ASSERTS THAT ANY REVENUES LOST AS A RESULT OF REDUCING THE $7.20 RS CUSTOMER CHARGE PROPOSED BY PP&L SHOULD BE RECOVERED SOLELY BY INCREASING THE "EARLY BLOCKS OF THE RESIDENTIAL RATE". DO YOU AGREE?

A. No. Mr. Kasper provides no evidence that supports the proposition that "higher initial blocks are appropriate to recover both demand or customer costs" (rebuttal pages 9-10). He also fails to document the claimed existence of a problem of intra-class subsidies. PP&L has declined to provide the data necessary to analyze differences in the usage characteristics of small and large RS customers. As discussed at pages 43 and 44 of my direct testimony, the data that is available suggests that there may be some justification for preserving the existing ($.0196 per kWh) RS tail block differential, but there is no evidence that supports the introduction of a third block in the RS rate, or a widening of the current difference between the initial and trailing block.

Q. MR. KASPER CLAIMS THAT THE REQUESTED INCREASE IN THE RS CUSTOMER CHARGE WOULD ENHANCE REVENUE STABILITY? DO YOU AGREE?

A. Yes. However, revenue stability is only one of several rate design objectives. Any increase in the RS customer charge larger than the overall increase in RS revenues will enhance revenue stability. Therefore, the $1.00 increase that I recommend would also enhance revenue stability. It should also be noted that Mr. Kasper provides no quantitative evidence regarding the magnitude or importance of the revenue stability benefit that he asserts.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

CEPFOD
EXHIBIT NO. 17

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PA. P.U.C v. Pennsylvania Power & Light Company
Docket No. R-00943271

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Rate		Bills	Present Revenue	Proposed Revenue	Increased Revenue	Percent Increase
All	Total	169,628	$19,227,366	$27,475,253	$8,247,887	42.90
RTS	Total	169,628	$19,227,366	$27,475,253	$8,247,887	42.90
RTS	Decrease	6,716	$552,633	$486,323	$-66,311	-12.00
RTS	Increase	162,904	$18,674,187	$26,988,385	$8,314,198	44.52
RTS	No Change	8	$546	$546	$0	0.00

RTS/RS Differential
Calculation. Page 1

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Page 2

Bills	169,628	Grand total of all bills
KWH	360,258,229	
Actual KW	978,227	
Billing KW	986,764	
Present Revenue ..	$19,227,365.60	
Proposed Revenue ..	$27,475,252.66	
Difference	$8,247,887.06	
Percent difference	42.90	

2.28

---------- Present rates ---------- RTS

Base revenue	$15,899,308.77
SBRCA	$-365,684.10
EDI	$0.00
STAS	$-74,560.96
ECR	$3,768,301.89
Present revenue ...	$19,227,365.60

---------- Proposed rates ---------- RS

Base revenue	$24,382,081.67
SBRCA	$-560,791.25
EDI	$0.00
STAS	$-114,339.65
ECR	$3,768,301.89
Present revenue ...	$27,475,252.66

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 9-R

Hbg TK R-943271
5/26/95

Rebuttal Testimony of John F. Sipics

Docket No. R-00943271

REBUTTAL TESTIMONY OF JOHN F. SIPICS

I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

Q. Please state your name and business address.

A. John F. Sipics. Two North Ninth St., Allentown, Pennsylvania, 18101.

Q. By whom are you employed and in what capacity?

A. I am employed by Pennsylvania Power & Light Company ("PP&L" or the "Company") as General Manager - Power Systems Support.

Q. Have you testified previously in this proceeding?

A. Yes. I submitted written direct testimony on December 30, 1994 (PP&L Statement 9), and I was cross-examined at hearings held on March 23, 1995.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to:

(1) Assertions by Mr. Matthew I. Kahal, on behalf of the Office of Consumer Advocate (OCA), and by Mr. Paul J. Metro, on behalf of the Office of Trial Staff (OTS), that PP&L has physical excess capacity.

(2) Assertions by Mr. Kahal that PP&L has economic excess capacity.

(3) Statements by Mr. Kenneth Eisdorfer, on behalf of University/College Coalition, and by Mr. Stephen J. Baron, on

behalf of the PP&L Industrial Customer Alliance (PPLICA) regarding the impact of load changes on PP&L's Installed Capacity Obligation.

(4) Statements by Mr. Maurice Brubaker, on behalf of Bethlehem Steel Corporation, regarding the relationship between PP&L's interruptible load rate and the cost of service.

Q. Please provide a summary of your conclusions.

A. My conclusions are as follows:

(1) PP&L does not have physical excess capacity:

- A reasonable reserve margin is not a single figure but a range. The Company's Installed Capacity Obligation to PJM establishes the bottom of that range. The upper bound must reflect a number of reliability and non-reliability considerations that are not incorporated in the PJM calculation of PP&L's Installed Capacity Obligation.
- The witnesses on behalf of the OTS and OCA have not adequately considered a number of factors that are relevant to establishing the reasonableness of the level of capacity resources. As a result, an appropriate upper bound for a reasonable reserve margin range is substantially above the figures those witnesses recommend.
- Commission-determined benchmarks for a reasonable reserve margin underscore the inadequacy of the OTS and OCA recommendations. The Commission has never imposed an excess capacity adjustment based on reserve margins as low as

15%-16%. In the Company's last base rate case, a 22% reserve margin was approved.

- In determining the resources to be included in an excess capacity analysis, the reasons for adding capacity and the timing of the addition relative to other resources must be considered. For example, because PP&L is required by law to purchase the output of cogenerators and other Qualifying Facilities, the capacity value of such resources should not be used to penalize the Company by displacing pre-existing generation in an excess capacity analysis.

(2) Susquehanna Unit 2 is not "economic" excess capacity:

- The "market price" test employed by the OCA's witness is not appropriate for determining whether Susquehanna Unit 2 provides net economic benefits because:
  - It is based on speculation about the way electric power markets will evolve in the future;
  - It ignores the prevailing environment of cost-based regulation;
  - If universally applied, it would likely render a substantial portion of all generation, nationwide, ineligible for rate base inclusion; and
  - It is based upon an estimate of a Market Clearing Price of Generation Study that was expressly identified as tentative; based upon assumptions that understate "market price;" and intended for a wholly different purpose.
- Although a "market price" analysis is clearly not appropriate, if it were to be employed, it should not be applied to an individual

asset on one utility's system.

(3) Contrary to the contentions of witnesses on behalf of the University/College Coalition and PPLICA, PP&L's Installed Capacity Obligation is not based exclusively on its winter peak load. Rather, it is affected by changes in peak loads during each week of the year.

(4) Contrary to the contention of Bethlehem Steel's witness, it would be improper and incorrect to assume that interruptible load does not cause PP&L to incur generation-related capital costs. PP&L's approach to pricing interruptible service properly reflects cost causation factors.

II. PHYSICAL EXCESS CAPACITY ISSUES

A. OCA WITNESS KAHAL

Q. Have you reviewed the conclusion of Mr. Kahal regarding physical excess capacity?

A. Yes, I have.

Q. Do you agree with Mr. Kahal's testimony that a 12 to 15% reserve margin is the appropriate level for PP&L?

A. No. He does not consider a number of factors that should be considered in determining the appropriateness of PP&L's level of capacity resources.

Q. Mr. Sipics, what are some of those additional factors?

A. Some factors that should be considered but were overlooked by Mr. Kahal include:

1. PP&L's PJM capacity obligation must be met both on a planning basis and on an "after-the-fact" accounting basis. PP&L's minimum 12% PJM reserve requirement is set two years in advance of the planning period. Following the completion of the PJM planning period, "after-the-fact" accounting adjustments are made to PP&L's obligation to reflect actual unit performance and loads. In addition, available capacity is reduced for peak period maintenance. All of these adjustments must be considered in developing an accurate characterization of PP&L's total capacity obligation. Within the last two years, these adjustments have increased PP&L's reserve level required for PJM installed capacity accounting purposes by as much as 5.3 percentage points (351 MW) above its planned obligation. (See Exhibit JFS-3). If PP&L is to avoid being penalized for having insufficient capacity in either the planned or the after-the-fact accounting used to determine PP&L's obligation to PJM, it is necessary to have reserves above the minimal 12% level.

2. There is significant exposure to relatively high unavailability of generating units in the winter due to the same weather conditions that contribute to the winter peak load. This is of particular concern to winter peaking utilities like PP&L. It is these conditions that led to the PJM capacity emergency that occurred on January 19, 1994. The PJM determination of reserve requirements, which is based on a detailed analytical modeling exercise, assumes that generating unit availability and load are independent events whereas, in reality, they are not. Therefore, this factor is not reflected in PP&L's 12% minimum reserve margin obligation to PJM.

3. In recent times, PJM has not been performing at a 1 in 10

reliability level even though overall planned PJM reserves have exceeded 22%. Since 1987, PJM has experienced 7 voltage reductions and, on January 19, 1994, rotating black-outs were necessary. This suggests that, even with reserves above the presently designated PJM reserve requirement, there is substantial risk that emergency procedures will need to be implemented more often than indicated by the planning objective.

Q. Mr. Sipics, are there any other factors, beyond reliability criteria, that you believe should be considered in determining whether PP&L's reserve margin is appropriate?

A. Yes, there are other factors that should be considered. Most importantly , a significant amount of the capacity resources that PP&L claims for PJM installed capacity accounting purposes was obtained for reasons other than reliability and was added <u>after</u> the construction of Susquehanna Unit 2, which consists of the following:

1. A capacity uprate of Susquehanna Unit 2 has been completed and an uprate of Susquehanna Unit 1 is underway. These uprates were undertaken to provide energy at a cost well below PP&L's avoided cost of energy (currently calculated to be 2.8¢/kWh). Specifically, the uprates provide energy at about 1.5¢/kWh, and have a capacity value to PP&L of 90 MW, which represents approximately 15% of what Mr. Metro and Mr. Kahal contend is physical excess capacity. An excess capacity disallowance based on a strict application of a reliability-based reserve requirement would discourage this type of cost-effective resource development.

2. The Public Utility Regulatory Policies Act of 1978 (PURPA) mandates the purchase of power from qualifying facilities (QFs) to encourage development of cogeneration and small power producers. PP&L makes no capacity payments to the QFs, reflecting the fact that PP&L did not need the QFs for capacity purposes. Because Non-Utility Generation (NUG), which includes all QFs, qualifies for recognition as capacity by PJM, PP&L has acted to maximize the economic benefits of these resources by claiming 474 MW of these unsolicited purchases for PJM accounting purposes in the 1995/96 winter period. An excess capacity disallowance based on a strict application of a reliability-based reserve requirement would penalize PP&L for purchasing QF output that, by law, it could not refuse.

3. After PUC review and approval, PP&L implemented Interruptible Load (IL) options to encourage economic development in central-eastern Pennsylvania. To maximize the benefits of these resources for PP&L and its customers, PP&L has claimed interruptible load for PJM installed capacity accounting purposes. These resources became eligible for recognition as capacity by PJM starting with the 1991/92 PJM planning period, and PP&L currently claims 345 MW of capacity credits for this type of load. An excess capacity disallowance based on a strict application of a reliability-based reserve requirement would discourage the use of these kinds of economic development initiatives.

With respect to NUG and IL, I would reiterate that, although PJM recognizes these resources as capacity for installed capacity accounting purposes, they were not added for the purpose of obtaining PJM capacity credits or for reliability reasons. Rather, having obtained those resources for other reasons, claiming them as capacity for PJM accounting purposes was a prudent management decision because it maximized the value of NUG and IL to PP&L and its customers. An excess capacity disallowance based upon a strict application of a reliability-based reserve requirement would unfairly penalize PP&L for making decisions that enhance the overall effective utilization of PP&L resources, such as its decisions to claim NUG and IL as capacity for PJM accounting and to undertake the Susquehanna capacity uprates to obtain additional low-cost energy.

Q. Are there any other factors that explain why PP&L's 12% reserve requirement to PJM should be considered only a minimum reserve level?

A. Yes. If conditions evolve as Mr. Kahal suggests, i.e., an increasingly competitive market develops, there is a significant potential that PJM will change in fundamental ways. A fully competitive market could force PP&L to provide capacity reserves on its own to maintain a 1 in 10 level of reliability. Such a "stand alone" scenario would likely require a substantial increase in PP&L's reserves in excess of its winter peak. This increase would result from the loss of benefits received in PJM for summer/winter diversity and emergency assistance provided by ties with, and supporting reserves from, neighboring utilities. These factors have benefited PP&L in the past, but are not guaranteed to continue in the future.

Moreover, as I will discuss more fully at a later point in this testimony, Mr. Kahal's position on physical and economic excess capacity are, in this respect, completely inconsistent. If the industry moves toward a competitive model, then PP&L could not rely upon PJM to the extent Mr. Kahal has assumed in developing his proposed physical excess capacity benchmark.

Q. Mr. Sipics, is there any precedent that should be considered in setting an appropriate reserve margin?

A. Yes. We can look at several benchmarks in the utility industry for precedent in determining an appropriate reserve margin. For example, there is no record of this Commission imposing an excess capacity disallowance on the basis of reserve levels as low as 12%-15%.

Additionally, when this Commission decided the Company's last base rate case in 1985, it found that a 22% reserve margin was appropriate. (See page 17 of the Order entered on April 25, 1985 at Docket No. R-842651). Because the Company's reserve margin was over 50% at the time of that decision, a return on its common equity investment in Susquehanna Unit 2 was disallowed. The Company's reserve margin has declined significantly over the past 10 years and is projected to remain considerably below the 22% benchmark for the foreseeable future based on PP&L's owned or leased capacity (less firm sales to other utilities).

When the Commission issued its ruling in 1985, it found that PP&L had about 1000 MW of excess capacity (i.e., capacity over and above that necessary to meet the 22% reserve requirement). Since 1985, PP&L's winter peak load has increased by slightly over 1000 MW. Additionally, since 1985, PP&L has not installed any new generating units. As explained above, all additional resources were acquired for reasons other than reliability.

Q. Based on these factors, can you explain how the upper boundary of a reasonable reserve margin range should be set?

A. As I stated in my direct testimony (see Statement No. 9, page 12, line 27 through page 13, line 14) and as previously mentioned in this statement, a minimum reserve level for reliability starts at 12%. From a reliability perspective, that reserve level should be increased for a variety of reliability related considerations. I have previously discussed three of these factors. One of these factors, the variation between forecasted and actual installed capacity obligations, could add more than 5 percentage points to the 12% minimum. Even if all three factors are not totally independent, something more than 5 percentage points would have to be added to the 12% PJM minimum. In addition, there are long-term planning factors that have potential reliability impacts. These include the "lumpiness" of generation additions that I have previously discussed in my direct testimony. Mr. Kahal quantifies this factor as equivalent to a 3 percentage point addition to the reliability-based reserve margin.

Q. Mr. Sipics, should capacity above the reliability-based reserve margin that you discussed be considered physical "excess capacity"?

A. No. The reasons for adding the capacity and the timing of its addition relative to other resources also must be considered. The Commission should allow itself the flexibility to include these kinds of considerations in its determination of whether capacity is "excess" for ratemaking purposes.

If a resource is added solely to obtain low cost energy, its capacity value should not be used to penalize the Company by displacing pre-existing generation in an "excess capacity" analysis. For example, as I previously explained, the capacity uprating of Susquehanna Units 1 and 2 provides extremely low-cost energy. It makes economic sense to pursue that source of low-cost energy irrespective of PP&L's existing installed capacity situation.

Also, if a resource is added because PP&L is required by law to purchase its output, as is the case with QFs, or because the resource was a consequence of PP&L's efforts to pursue economic development initiatives, as was the case with IL, then the capacity value of such resources likewise should not be used to penalize the Company by displacing pre-existing generation in an "excess capacity" analysis.

Obviously, in each instance, the timing of the capacity resource addition is significant, which is why I emphasize that the three resources I have identified above should not displace "pre-existing" generation. However, the Susquehanna uprating, NUG and IL could properly be included in assessing whether a <u>subsequent</u> capacity addition is needed for reliability reasons or is "excess" for ratemaking purposes.

B. OTS WITNESS METRO

Q. Have you reviewed the testimony of Mr. Paul J. Metro regarding physical excess capacity?

A. Yes, I have.

Q. Please address Mr. Metro's contention that PP&L's resources above a 16% reserve margin constitute physical excess capacity.

A. For the reasons I have discussed in response to Mr. Kahal's testimony, when reliability and other relevant factors are considered, an appropriate upper bound for PP&L's reserve margin in this case is substantially above the 16% recommended by Mr. Metro. While I agree with Mr. Metro's conclusion that an economic excess capacity test should not be applied to Susquehanna Unit

2, I disagree with his judgment that PP&L has <u>physical</u> excess capacity. Furthermore, Mr. Metro's failure adequately to consider the timing and reasons for the addition of the resources he included in his excess capacity analysis leads to a fundamentally unfair result. This is exemplified by Mr. Metro's answers to questions on cross-examination concerning a hypothetical situation in which the Federal government mandated PP&L's acquisition of 1,000 MW of capacity from TVA.

Mr. Metro conceded that his approach is indifferent to the source of, or reason for, that 1,000 MW of capacity addition, which could be used as the basis for an "excess capacity" adjustment to deny PP&L a return on 1,000 MW of its pre-existing generation (see Transcript, p. 1521). Of course, PP&L's purchases of NUG output are comparable to the hypothetical, mandated purchase from TVA, because PURPA allowed PP&L no option other than to accept NUG output that was offered to it for sale.

Q. Mr. Sipics, have you replicated Mr. Metro's reserve margin calculation using his methodology and inputs but excluding QFs?

A. Yes, that calculation is set forth in Exhibit JFS-4. As shown on that Exhibit, the average "excess available resources" for the entire 1995-2004 period is only 90 MW, which is equal to PP&L's share of the Susquehanna upratings. However, a <u>shortfall</u> of about 100 MW would occur in the 1995/96 period, which approximates the first year that rates established in this case would be in effect. For the entire nine-year period, the reserves at the time of peak, without QFs, produce an average reserve margin of 17.05%.

Q. Has Mr. Metro offered any information that would support the exclusion of interruptible load from PP&L's resources in his "excess available resource" calculation?

A. Yes. In his response to a PP&L Interrogatory, which is provided as Exhibit JFS-5, Mr. Metro affirmed that interruptible peak reduction capability is available for only a limited number of occurrences of limited duration and that it can be less desirable than peaking-type generating units because it is not directly controlled by the utility and requires more lead time to initiate. Although not mentioned by Mr. Metro, interruptible load was added by PP&L subsequent to the construction of Susquehanna Unit 2 and was added for economic development, not reliability, purposes. For the reasons I have previously explained, this factor also supports the exclusion of interruptible load from the "excess available resource" calculation.

Q. Mr. Sipics, have you replicated Mr. Metro's calculation using his methodology and inputs but excluding QFs and IL?

A. Yes, that calculation is set forth in Exhibit JFS-6. As shown in that Exhibit, PP&L's reserves at the time of peak, excluding QFs and IL, produce reserve margins that range between 9.06% and 14.87% during the 1995-2004 period. Over that period, PP&L would fall short of Mr. Metro's 16% reserve margin target by an average of 255 MW per year.

Q. Mr. Sipics, please explain the relationship between Mr. Metro's proposed adjustment and the Company's proposal for the ratemaking treatment of the capacity returning to PP&L from the expiring firm capacity sale to Jersey Central Power & Light Company (JCP&L)?

A. In response to questions on cross-examination, Mr. Metro confirmed: (1) that he has included in available resources over the period 1995-2004 the capacity returning to PP&L from the expiring JCP&L sale; and (2) if that capacity were not treated as an available resource for Pennsylvania jurisdictional purposes, his calculations would not show any excess capacity. (Transcript, pp. 1522-23). As explained in Mr. Kleha's direct testimony (Statement No. 7, pp. 21-25), PP&L is proposing a change to its Energy Cost Rate (ECR) to include all capacity sale revenue upon the condition that the Commission accept the Company's proposal to include in the ECR all fixed costs associated with the capacity returning from the JCP&L sale. If the Company's ECR proposals are not adopted, then Pennsylvania jurisdictional ratepayers would not bear any costs associated with the capacity returning from JCP&L. Under those circumstances, that capacity should not be included in Mr. Metro's calculation.

Q. In PP&L's most recent base rate proceeding, what level of reserve margin did the OTS indicate would be appropriate for PP&L to maintain?

A. The OTS witness at that time, Mr. Michael Gruber, testified that a reserve margin of approximately 22% would be appropriate.

Q. Has Mr. Metro explained what changes, if any, have occurred since PP&L's last base rate case that would invalidate the previous OTS finding that a 22% reserve margin is appropriate?

A. No. Mr. Metro has offered no explanation for reducing PP&L's appropriate reserve margin from 22% to 16%.

Q. Do you know of any factors that have changed since PP&L's last rate case that would decrease PP&L's appropriate reserve level?

A. No. PP&L continues to be a winter peaking utility in a summer peaking power pool.

Q. How did OTS witness Gruber calculate the 22% reserve margin he proposed in PP&L's last base rate case?

A. Mr. Gruber calculated a PP&L reserve margin by doubling PP&L's five-year average forced outage rate of 11%.

Q. If you were to replicate the OTS calculation in the last rate case, using updated data, what reserve margin would be considered appropriate for PP&L?

A. Using an averaging method similar to that of Mr. Gruber, PP&L's forced outage rate for the period 1990 to 1994 would be 8.9%. Therefore, applying Mr. Gruber's approach to that average forced outage rate would yield a reserve margin of 17.8%.

III. ECONOMIC EXCESS CAPACITY ISSUES

Q. Have you reviewed the testimony of Mr. Kahal regarding economic excess capacity?

A. Yes, I have.

Q. Mr. Kahal contends that because the full revenue requirement of Susquehanna Unit 2 in the near term exceeds a hypothetical market price of power, an equity return on the unit should not be allowed. Do you agree with his approach for measuring economic excess capacity?

A. No. While I have not performed a detailed analysis, it is my view that application of Mr. Kahal's approach, i.e., comparing unit costs to market value to determine the appropriateness of including a unit in rate base, would likely result in the exclusion from rate base of a substantial portion of all generation assets nation-wide. This issue has received considerable attention from a wide range of interested parties, including utilities and regulators, and is frequently termed the "stranded investment" problem. Resolution of this issue is not the purpose of this case. This issue will be addressed as part of the FERC Notice of Proposed Rulemaking (NOPR) on Recovery of Stranded Investment (Docket RM 94-7-001) and other similar proceedings.

Q. Is a market price test the correct approach for measuring the appropriateness of including Susquehanna Unit 2 in rate base?

A. No. While there are indications that electric generation is becoming more competitive, and that future returns on investment may be based on market conditions, the current, prevailing economic environment continues to be one of cost based regulation.

Q. In Mr. Kahal's testimony, he refers to a PP&L study entitled Market Clearing Price of Generation (MCPG) in which PP&L attempts to project the market price of power. Is this estimate an appropriate means for measuring the economic value of Susquehanna?

A. No. The MCPG Study offers only one hypothetical view of the future. The analysis provided a very preliminary estimate of the market price of generation in a <u>fully competitive</u> electricity market (i.e., with both wholesale and retail wheeling). The analysis assumes one scenario of the future of the electric utility industry. Many other scenarios are also plausible. In addition, the MCPG Study employed generally conservative assumptions and methods, which most likely understate the competitive market prices of electricity. The information in the MCPG Study was designed for broad strategy discussions and to set aggressive targets for PP&L to attempt to attain. The study cannot be considered a definitive or complete analysis of the factors that determine economic value. Mr. Kahal's reliance upon the results of that analysis, therefore, is not appropriate.

Q. Please describe some of the factors in PP&L's MCPG analysis that would act to understate the estimate of the future market price of electricity.

A. PP&L's MCPG analysis did not remove generation from the regional mix if the cost of such generation was likely to be above the MCPG. If those units were removed, the market price clearly would be driven up. A more sophisticated analysis than was performed by PP&L would be required to estimate these effects.

Q. Can you describe any other factors in PP&L's MCPG analysis that would tend to understate market prices?

A. The MCPG was driven down by the fact that much of the QF generation in the region is must-run. If such units were dispatched at incremental costs, the MCPG likely would be higher. Also, operating costs for fossil-fired generation assume no required nitrogen oxide (NOx) control beyond Reasonable Available Control Technology (RACT). If NOx targets are set such that RACT would not be adequate to assure compliance, the MCPG would increase materially.

Q. Are Mr. Kahal's determinations of physical and economic excess capacity consistent?

A. No. Mr. Kahal does not apply a consistent view of future market conditions in his analysis of PP&L's capacity position. On one hand, Mr. Kahal argues that the hypothetical MCPG that might exist in a fully competitive market is the appropriate test for determining economic excess capacity. On the other hand, Mr. Kahal argues that the assessment of whether physical excess capacity exists should not consider changes likely to occur in a more competitive market, but instead should be based solely on PP&L's current Installed Capacity Obligation. These arguments are clearly inconsistent and yield unsupportable results.

Q. If a market price index were an appropriate measure of economic value in a regulated environment, would it be fair to apply the test to individual assets, or should the portfolio of assets be considered?

A. Each of the Company's assets has a unique value. At a particular time, the value of a specific asset may be greater or less than its cost. If a market test were to be applied, the critical test should be whether the composite value of assets exceeds the composite cost of these assets. On this basis, therefore, it is inappropriate to evaluate Susquehanna Unit 2 as an isolated asset. It simply is not appropriate to evaluate any individual facility on one utility's system based on a market price analysis.

IV. COST ALLOCATION: IMPACT OF LOAD CHANGES ON PP&L'S INSTALLED CAPACITY OBLIGATION

Q. Have you reviewed the testimony of Mr. Kenneth Eisdorfer regarding the impact of load changes on the Company's Installed Capacity Obligation (ICO)?

A. Yes, I have.

Q. Do you agree with Mr. Eisdorfer's opinion that the manner in which PJM determines PP&L's ICO does not support the use of the 12 CP method of capacity cost allocation?

A. No. Mr. Eisdorfer bases this position upon his conclusion that "PP&L's winter peaks are the overwhelming determinant of PP&L's ICO." This contention is incorrect for two reasons:

- First, the PJM reserve requirement is calculated using 52 weekly peak load probability distributions; and
- Second, PP&L's ICO is increased slightly more by an increase in PP&L's summer peak than by a similar increase in PP&L's winter peak.

Q. Would you please explain how the 52 weekly peak load probability distributions are used to calculate the PJM Installed Capacity Requirement?

A. A determination of the amount of installed capacity required to meet the 1 day in ten years loss of load expectation (LOLE) is based on a LOLE calculation which combines the PJM load and capacity models. The load model used in this calculation consists of 52 weekly peak loads and a distribution of 5 daily peak loads about the weekly peaks (weekends are not included). This model is constructed from 5 years of historical load data. The PJM Installed Capacity Requirement is based on limiting the annual cumulative loss of load expectation for each of the 52 weeks to 1 day in ten years. Therefore, the PJM Installed Capacity Requirement is based on 52 weekly loads and not just the winter peak load.

Q. Would you explain why PP&L's allocated share of the PJM Installed Capacity Requirement would increase more for an increase in summer peak load than for an equal increase in winter peak load?

A. The PJM Installed Capacity Requirement discussed above is allocated to the individual PJM companies. The allocation of the PJM Installed Capacity

Requirement to PP&L is primarily based on the determination of PP&L's Diversified Planning Period Peak (DPPP). The determination of PP&L's ICO is based on the product of the DPPP and one plus the calculated company reserve requirement (See JFS-7, page 1).

The DPPP for a winter peaking company, like PP&L, is equal to the average of the Company's winter peak loads (decreased by the summer/winter unit capacity difference) for the winters preceding and following the PJM summer peak, less one-half the Company's summer/winter peak load diversity and PP&L's share of the PJM summer load diversity. Based on this calculation, a specific increase in either the summer peak load or winter peak load will produce a virtually identical increase in PP&L's DPPP. This effect is illustrated in the sample calculations provided in pages 2 and 3 of Exhibit JFS-7 which show the change in PP&L's DPPP for a 100MW increase in PP&L's summer peak or a 100MW increase in PP&L's winter peak.

As noted above, PP&L's ICO is the product of the DPPP and the PP&L reserve requirement. PP&L's reserve requirement is determined by adjusting the PJM reserve requirement by the Forced Outage Rate Adjustment and Load Drop Adjustment. (See page 3 of Attachment 1 of PP&L's response to Question OTS-RB-28D of Interrogatories of the Office of Trial Staff Dated January 13, 1995). As Mr. Eisdorfer recognizes, PP&L's Load Drop Adjustment currently increases PP&L's reserve requirement. However, this adjustment is slightly higher for an increase in summer peak load than for an equal increase in winter peak load. As a result, the PP&L ICO will increase somewhat more for an increase in summer peak load than for an equal increase in winter peak load.

Q. In your opinion, are Mr. Eisdorfer's comments and analysis related to PP&L's ICO and the use of the 12 CP method of capacity cost allocation flawed?

A. Yes, as demonstrated above, his analysis and comments do not reflect a correct understanding of the elements comprising PP&L's ICO and, therefore, his contentions related to the 12 CP cost allocation method are in error.

Q. Have you reviewed the testimony of Mr. Baron regarding the impact of load changes on PP&L's ICO?

A. Yes, I have.

Q. Do you agree with Mr. Baron's assertion that "PP&L's primary obligation is to maintain a 12% reserve margin over the Company's winter peak, not the average of the Company's twelve peaks"?

A. No. I do not agree that PP&L's ICO is determined based primarily on the requirement to meet the Company's annual winter peak load, for the reasons previously explained in my response to Mr. Eisdorfer's similar conclusions regarding the manner in which PJM determines PP&L's ICO. PP&L's actual ICO is PP&L's share of the PJM Installed Capacity Requirement, which is designed to maintain a one day in ten year LOLE. The PJM Installed Capacity Requirement is determined using 52 weekly peak load probability distributions. The winter peak is represented by only one of the 52 weeks used in the PJM LOLE calculation. The 12% reserve margin is simply PP&L's ICO expressed as a percentage of the Company's winter peak load.

Q. Do you agree with Mr. Baron's assertion that the scheduling of generation equipment for maintenance is not a factor in the addition of generating capacity to the PP&L system?

A. No. As I explained previously, the PJM Installed Capacity Requirement is based on a LOLE calculation using 52 weekly peak load probability distributions. The LOLE calculation includes adjustments in each week to represent anticipated levels of generating equipment scheduled to be out of service for maintenance in each week of the year. Therefore, planned maintenance is clearly considered in the way PJMs sets the Company's ICO.

Q. In your opinion, are Mr. Baron's comments related to PP&L's ICO and the use of the 12 CP method of capacity cost allocation flawed?

A. Yes, as I noted previously with regard to Mr. Eisdorfer's comments, Mr. Baron's comments do not reflect a correct understanding of the elements compromising PP&L's ICO and, therefore, his assertions related to the 12 CP cost allocation method also are in error.

V. PRICING INTERRUPTIBLE SERVICE

Q. Have you reviewed the testimony of Mr. Maurice Brubaker regarding the relationship between PP&L's interruptible load rate and the cost of service?

A. Yes, I have.

Q. Are Mr. Brubaker's comments related to the need to adjust the $300 per kW investment "credit" assignment to interruptible load by a factor of 1.19 (PJM ALM Adjustment) accurate?

A. Yes. I do not disagree with this conclusion. However, even with this adjustment, the capacity-related value of interruptible load is considerably less than the allowance reflected in the Company's proposed rates. This matter is discussed more fully in the rebuttal testimony of O. G. Kasper.

Q. Do you agree with Mr. Brubaker's contention that interruptible load does not cause PP&L to incur any generation-related capital costs and that PP&L can avoid planning to install capacity to serve that portion of the load?

A. No. At most, interruptible load only helps PP&L to avoid the capital costs for peaking facilities, such as combustion turbines (CTs), that are installed primarily for their capacity value, i.e., the ability to produce energy over a defined time period. While CTs have capacity value, their overall value is substantially less than other types of generation because they cannot produce relatively low cost energy over an extended time period. Providing interruptible customers with energy from CTs alone would result in a relatively costly supply source. For this reason, PP&L plans a mix of generation (i.e., peaking, intermediate-load, and base-load) to provide efficient energy supply for all customers, including interruptible customers.

Q. Does interruptible load provide the same value as base-load and intermediate-load generation?

A. No. Interruptible load, similar to peaking capacity, is used infrequently for relatively short durations to meet peak load or emergency conditions. As a result, interruptible load provides very little energy value. In contrast to interruptible load or peaking capacity, base-load and intermediate-load generation can operate for extended periods and provide significant amounts of relatively low cost energy. The installed cost of base-load generation is significantly higher than peaking capacity, but energy-related costs are significantly lower. Intermediate-load generation has capital related costs between base-load and peaking generation and, correspondingly, its energy costs fall between those of base-load and peaking capacity. Thus, different types of capacity provide different benefits and have different costs. Because interruptible customers realize the energy benefits of base-load and intermediate-load generation, they should also share in the overall costs of such units.

Q. Would interruptible load defer the need for base-load or intermediate-load generation?

A. No. As noted above, these generation types provide a type of resource completely different from interruptible load.

Q. Do you agree with Mr. Brubaker's assertion that assigning interruptible load a capacity credit equal to the estimated cost of a CT does not reflect the principles of cost-causation?

A. No. PP&L's interruptible rate relates to the costs associated with a comparable alternative, i.e., combustion turbine capacity.

Q. What is the current value of interruptible load on PP&L's system?

A. The cost for PP&L to replace the peaking capacity from interruptible load would range from the annual carrying cost of a CT (currently estimated to be about $45/kW-yr) to a short-term market price for capacity as low as about $15/kW-year, depending on supply and demand for the particular time frame.

Q. How has that value changed over the past several years?

A. The short-term market price has declined from about $50/kW-year in 1988 to as low as $15/kW-year in 1994. When the amount of capacity available for installed capacity purposes on the PJM declines, the market price of capacity credits and the value of capacity made available by interruptible load will approach the full carrying charges of a CT.

Q. In view of the factors outlined above, what is the effect on PP&L's cost structure of having interruptible load?

A. The maximum value of interruptible load, reflected in PP&L's cost structure for rate-making purposes, should be based on the annual carrying cost of a combustion turbine.

Q. Have you concluded that Mr. Brubaker's "adjusted" cost of service study is flawed and inappropriate?

A. Yes. Based on the preceding discussion, it is evident that Mr. Brubaker does not properly consider the allocation of generation cost and, therefore, reaches an incorrect result. PP&L's cost-allocation approach properly reflects the cost to serve interruptible customers.

Q. Does that complete your testimony?

A. Yes, it does.

PP&L PLANNED AND ACTUAL WINTER RESERVE REQUIREMENT
1991/92 THROUGH 1994/95

	1991/92	1992/93	1993/94	1994/95*
Forecast PP&L System Resource Requirement (Winter MW)	6609	7111	7180	7361
Diversified Planning Period Peak Adjustment (MW)	-148	-456	-130	66
Average Unavailable Adjustment (MW)	-78	-68	254	55
Maximum Peak Period Maintenance Adjustment (MW)	808	475	238	132
PP&L Summer-Winter Capacity Difference (MW)	20	21	-11	
Actual PP&L System Resource Requirement (MW)	7211	7083	7531	7614
Change in PP&L System Resource Requirement (MW)	602	-28	351	253
Forecast PP&L System Winter Peak Load (MW)	6360	6680	6580	6630
Change in the PP&L System Winter Reserve Requirement (Percentage Points of Winter Peak)	9.47	-0.42	5.33	3.82

* Based on PP&L last forecast for the 1994/95 Planning Period that will end 5/31/95.

Exhibit JFS-3

Excess Capacity Calculations	(With Forced Outages excluded from resources)									
	1995/1996	1996/1997	1997/1998	1998/1999	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004	
	MW	MW	MW	MW	MW	MW	MW	MW	MW	
Net Resrces @ Peak Time	7,334	7,523	7,760	7,954	8,120	8,420	8,552	8,552	8,552	
Plus: Interruptible Load	345	345	345	345	345	345	345	345	345	
~~Plus: NUG~~	~~474~~	~~474~~	~~474~~	~~474~~	~~474~~	~~474~~	~~474~~	~~474~~	~~474~~	
Total Available Resources	~~8,153~~ 7679	~~8,342~~ 7868	~~8,579~~ 8165	~~8,773~~ 8299	~~8,939~~ 8465	~~9,239~~ 8765	~~9,371~~ 8897	~~9,371~~ 8897	~~9,371~~ 8897	
Minus: Forced Outages	250	256	264	271	277	287	291	291	291	
Net Available Resources	~~7,903~~ 7429	~~8,086~~ 7612	~~8,315~~ 7841	~~8,502~~ 8028	~~8,662~~ 8188	~~8,952~~ 8478	~~9,080~~ 8606	~~9,080~~ 8606	~~9,080~~ 8606	
Winter Peak Load	6,725	6,790	6,915	7,050	7,185	7,330	7,465	7,600	7,745	
PJM Requirement (1.12%)	7532	7605	7745	7896	8047	8210	8361	8512	8674	
Excess Available Resources	~~371~~ (103)	~~481~~ 7	~~570~~ 96	~~606~~ 132	~~615~~ 141	~~743~~ 268	~~719~~ 245	~~568~~ 94	~~405~~ (68)	90
								9 Year Average		~~564~~

Reserves at the Time of Peak (MW)										
	1995/1996	1996/1997	1997/1998	1998/1999	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004	9 YEAR AVERAGE
Plus: Interruptible Load	14.19%	15.88%	17.21%	17.72%	17.81%	19.58%	19.18%	17.07%	14.87%	17.05 %
~~Plus: NUG~~	~~21.23%~~	~~22.86%~~	~~24.06%~~	~~24.44%~~	~~24.41%~~	~~26.04%~~	~~25.53%~~	~~23.30%~~	~~20.99%~~	
Minus: Forced Outages	~~17.52%~~ 10.47	~~19.08%~~ 12.11	~~20.24%~~ 13.39	~~20.60%~~ 13.87	~~20.56%~~ 13.46	~~22.13%~~ 15.66	~~21.63%~~ 15.28	~~19.47%~~ 13.23	~~17.23%~~ 11.11	13.23 %

Source: Company Exhibit JFS-1

Exhibit JFS-4

Pennsylvania Power & Light Company
Docket No. R-00943271

Answers of Office of Trial Staff
to Interrogatories of
Pennsylvania Power & Light Company

SET II

Engineer: P. Metro

Q9. Is Mr. Metro aware of any limitations on the availability of capacity resources represented by interruptible load customers? If yes, please identify those limitations.

A9. Yes. PP&L Statement No. 9, page 13, lines 18-30, discuss the limitations on the availability of capacity resources represented by interruptible load customers. Mr. Sipics states:

> **"...its [interruptible load] peak reduction capability is available for only a limited number of occurrences of limited duration. The frequency and duration limitations are a function of the tariff and contract provisions necessary to create reasonable incentives for customers to accept non-firm service....While interruptible load is, in general, comparable to peaking capacity, it can be less desirable than peaking-type generating units, such as quick-start combustion turbines, because it is not directly controlled by the utility and requires more lead time to initiate."**

Excess Capacity Calculations	(With Forced Outages excluded from resources)									
	1995/1996	1996/1997	1997/1998	1998/1999	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004	
	MW	MW	MW	MW	MW	MW	MW	MW	MW	
Net Resrces @ Peak Time	7,334	7,523	7,760	7,954	8,120	8,420	8,552	8,552	8,552	
~~Plus: Interruptible Load~~	~~345~~	~~345~~	~~345~~	~~345~~	~~345~~	~~345~~	~~345~~	~~345~~	~~345~~	
~~Plus: NUG~~	~~474~~	~~474~~	~~474~~	~~474~~	~~474~~	~~474~~	~~474~~	~~474~~	~~474~~	
	7334	7523	7760	7954	8120	8420	8552	8552	8552	
Total Available Resources	~~8,153~~	~~8,342~~	~~8,579~~	~~8,773~~	~~8,939~~	~~9,239~~	~~9,371~~	~~9,371~~	~~9,371~~	
Minus: Forced Outages	250	256	264	271	277	287	291	291	291	
	7084	7267	7496	7683	7843	8133	8261	8261	8261	
Net Available Resources	~~7,903~~	~~8,086~~	~~8,315~~	~~8,502~~	~~8,662~~	~~8,952~~	~~9,080~~	~~9,080~~	~~9,080~~	
Winter Peak Load	6,725	6,790	6,915	7,050	7,185	7,330	7,465	7,600	7,745	
PJM Requirement (1.12%)	7532	7605	7745	7896	8047	8210	8361	8512	8674	
	(448)	(338)	(249)	(213)	(204)	(77)	(100)	(251)	(413)	(255)
Excess Available Resources	~~371~~	~~481~~	~~570~~	~~606~~	~~615~~	~~743~~	~~719~~	~~568~~	~~405~~	
									9 Year Average	~~584~~

Reserves at the Time of Peak (MW)										
	1995/1996	1996/1997	1997/1998	1998/1999	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004	
~~Plus: Interruptible Load~~	~~14.19%~~	~~15.88%~~	~~17.21%~~	~~17.72%~~	~~17.81%~~	~~19.58%~~	~~19.18%~~	~~17.07%~~	~~14.87%~~	
~~Plus: NUG~~	~~21.23%~~	~~22.86%~~	~~24.06%~~	~~24.44%~~	~~24.41%~~	~~26.04%~~	~~25.53%~~	~~23.30%~~	~~20.99%~~	9 YEAR AVERAGE
	9.06	10.80	12.22	12.82	13.01	14.87	14.56	12.53	10.42	12.25 %
	5.34	7.03	8.40	8.98	9.16	10.96	10.66	8.70	6.66	8.43 %
Minus: Forced Outages	~~17.52%~~	~~19.08%~~	~~20.24%~~	~~20.60%~~	~~20.56%~~	~~22.13%~~	~~21.63%~~	~~19.47%~~	~~17.23%~~	

Source: Company Exhibit JFS-1

Exhibit JFS-6

Official 1994-1995 Planning Period

Base Case

PLANNING PERIOD 1994 - 1995 06/01 TO 06/01

ALLOCATION OF PJM FORECAST REQUIREMENTS

DETERMINATION OF PJM FORECAST DIVERSIFIED PLANNING PERIOD PEAKS (P) - SCHEDULE 2.211

28-Apr-95

PLANNING PERIOD 1994 - 1995

PJM FORECAST SUMMER PEAK - 46207

PEAKS AND CAPABILITIES IN MW, RATIOS IN %

	PS	PE	PL	BC	GPU	PEP	AE	DPL	TOT	PJM	
PLANNING PERIOD PEAK DETERMINATION:											
1 FORECAST SUMMER PEAKS			5570						46669		INPUT
TOT NET CAPABILITIES - 12-1-94:											
2 SUMMER CONDITIONS			7270						55841		INPUT
3 WINTER CONDITIONS			7481						58535		INPUT
4 WINTER MINUS SUMMER CAPABILITY			211						2694		L3 - L2
5 FORECAST WINTER PEAKS			6630						40927		INPUT
6 REDUCED WINTER PEAKS			6419						38233		L5 - L4
WINTER PEAKING SYSTEMS = (L6>L1):											
7 PRESENT FORECAST OF LAST PLANNING PERIOD WINTER PEAKS			6470								INPUT
TOT NET CAPABILITIES - 12-1-93:											
8 SUMMER CONDITIONS			7268								INPUT
9 WINTER CONDITIONS			7478								INPUT
10 WINTER MINUS SUMMER CAPABILITY			210								L9 - L8
11 REDUCED WIN PKS THIS PL PER			6419								L6
12 REDUCED WIN PKS LAST PL PER			6260								L7 - L10
13 GREATER OF SUM PK THIS PL PER OR REDUCED WIN PK LAST PL PER			6260								GREATER (L1 OR L12)
14 WIN PEAKING SYSTEMS PL PER PK			6339.5								(L11 + L13) / 2
PLNG PD DIVERSITY DETERMINATION:											
15 WIN SYS: DIFF BETWEEN WIN SYS PLAN PER PK & SUMMER PK			769.5						769.5		L14 - L1
16 SUMMER SYSTEM: DIFF BETWEEN SU PEAK AND REDUCED WINTER PEAK									9265		L1 - L6
17 RATIO OF CO. DIFF TO TOT (L16)											CO L16 / TOT L16
18 WINTER PK SYS PLAN PER DIV			770						770		(CO L15/TOT L15) * LESSER (TOT L15 OR TOT L16)
19 WIN PK SYS SHARE-PLN PER DIV			385						385		50% CO L18
20 SUM PK SYS SHARE-PLN PER DIV									385		50% TOT L18 * L17
SUMMER DIVERSITY DETERMINATION:											
21 RATIO-CO. SUMMER PEAKS TO TOTAL PJM SUMMER PEAKS			11.90								CO L1 / TOTAL L1
22 SUMMER PEAK DIVERSITY									462		TOT L1 - PJM SUMMER PEAK
23 ALLOCATION-SUM PK DIVERSITY			55						462		L21 * L22
DIVERSIFIED PLANNING PERIOD PEAKS:											
24 WINTER PEAKING SYSTEMS			5900						5900		L14 - L19 - L23
25 SUMMER PEAKING SYSTEMS									40308		L1 - L20 - L23
26 PJM PLANNING PERIOD PEAK										46207	TOT L24 + TOT L25

Exhibit JFS-7
1 of 3

Official 1994-1995 Planning Period

Summer Load Increased 100 MW

PLANNING PERIOD 1994 - 1995 06/01 TO 06/01

ALLOCATION OF PJM FORECAST REQUIREMENTS

DETERMINATION OF PJM FORECAST DIVERSIFIED PLANNING PERIOD PEAKS (P) - SCHEDULE 2.211

28-Apr-95

PLANNING PERIOD 1994 - 1995

PJM FORECAST SUMMER PEAK - 46307

PEAKS AND CAPABILITIES IN MW, RATIOS IN %

	PS	PE	PL	BC	GPU	PEP	AE	DPL	TOT	PJM	
PLANNING PERIOD PEAK DETERMINATION:											
1 FORECAST SUMMER PEAKS			5670						46769		INPUT
TOT NET CAPABILITIES - 12-1-94:											
2 SUMMER CONDITIONS			7270						55841		INPUT
3 WINTER CONDITIONS			7481						58535		INPUT
4 WINTER MINUS SUMMER CAPABILITY			211						2694		L3 - L2
5 FORECAST WINTER PEAKS			6630						40927		INPUT
6 REDUCED WINTER PEAKS			6419						38233		L5 - L4
WINTER PEAKING SYSTEMS = (L6>L1):											
7 PRESENT FORECAST OF LAST PLANNING PERIOD WINTER PEAKS			6470								INPUT
TOT NET CAPABILITIES - 12-1-93:											
8 SUMMER CONDITIONS			7268								INPUT
9 WINTER CONDITIONS			7478								INPUT
10 WINTER MINUS SUMMER CAPABILITY			210								L9 - L8
11 REDUCED WIN PKS THIS PL PER			6419								L6
12 REDUCED WIN PKS LAST PL PER			6260								L7 - L10
13 GREATER OF SUM PK THIS PL PER OR REDUCED WIN PK LAST PL PER			6260								GREATER (L1 OR L12)
14 WIN PEAKING SYSTEMS PL PER PK			6339.5								(L11 + L13) / 2
PLNG PD DIVERSITY DETERMINATION:											
15 WIN SYS: DIFF BETWEEN WIN SYS PLAN PER PK & SUMMER PK			669.5						669.5		L14 - L1
16 SUMMER SYSTEM: DIFF BETWEEN SU PEAK AND REDUCED WINTER PEAK									9285		L1 - L6
17 RATIO OF CO. DIFF TO TOT (L16)											CO L16 / TOT L16
18 WINTER PK SYS PLAN PER DIV			670						670		(CO L15/TOT L15) * LESSER (TOT L15 OR TOT L16)
19 WIN PK SYS SHARE-PLN PER DIV			335						335		50% CO L18
20 SUM PK SYS SHARE-PLN PER DIV									335		50% TOT L18 * L17
SUMMER DIVERSITY DETERMINATION:											
21 RATIO-CO. SUMMER PEAKS TO TOTAL PJM SUMMER PEAKS			12.10								CO L1 / TOTAL L1
22 SUMMER PEAK DIVERSITY									462		TOT L1 - PJM SUMMER PEAK
23 ALLOCATION-SUM PK DIVERSITY			56						463		L21 * L22
DIVERSIFIED PLANNING PERIOD PEAKS:											
24 WINTER PEAKING SYSTEMS			5949						5949		L14 - L19 - L23
25 SUMMER PEAKING SYSTEMS									40357		L1 - L20 - L23
26 PJM PLANNING PERIOD PEAK										46306	TOT L24 + TOT L25

Summer peak increased by 100 MW

DPPP increased by 49 MW

Exhibit JFS-7
2 of 3

P/

Official 1994-1995 Planning Perioa

Winter Load Increased 100 MW

PLANNING PERIOD 1994 - 1995 06/01 TO 06/01

ALLOCATION OF PJM FORECAST REQUIREMENTS

PAGE 1

DETERMINATION OF PJM FORECAST DIVERSIFIED PLANNING PERIOD PEAKS (P) - SCHEDULE 2.211

28-Apr-95

PLANNING PERIOD 1994 - 1995

PJM FORECAST SUMMER PEAK - 46207

PEAKS AND CAPABILITIES IN MW, RATIOS IN %

	PS	PE	PL	BC	GPU	PEP	AE	DPL	TOT	PJM	
PLANNING PERIOD PEAK DETERMINATION:											
1 FORECAST SUMMER PEAKS			5570						46669		INPUT
TOT NET CAPABILITIES - 12-1-94:											
2 SUMMER CONDITIONS			7270						55841		INPUT
3 WINTER CONDITIONS			7481						58535		INPUT
4 WINTER MINUS SUMMER CAPABILITY			211						2694		L3 - L2
5 FORECAST WINTER PEAKS			6730						41027		INPUT
6 REDUCED WINTER PEAKS			6519						38333		L5 - L4
WINTER PEAKING SYSTEMS = (L6>L1):											
7 PRESENT FORECAST OF LAST PLANNING PERIOD WINTER PEAKS			6570								INPUT
TOT NET CAPABILITIES - 12-1-93:											
8 SUMMER CONDITIONS			7268								INPUT
9 WINTER CONDITIONS			7478								INPUT
10 WINTER MINUS SUMMER CAPABILITY			210								L9 - L8
11 REDUCED WIN PKS THIS PL PER			6519								L6
12 REDUCED WIN PKS LAST PL PER			6360								L7 - L10
13 GREATER OF SUM PK THIS PL PER OR REDUCED WIN PK LAST PL PER			6360								GREATER (L1 OR L12)
14 WIN PEAKING SYSTEMS PL PER PK			6439.5								(L11 + L13) / 2
PLNG PD DIVERSITY DETERMINATION:											
15 WIN SYS: DIFF BETWEEN WIN SYS PLAN PER PK & SUMMER PK			869.5						869.5		L14 - L1
16 SUMMER SYSTEM: DIFF BETWEEN SU PEAK AND REDUCED WINTER PEAK									9285		L1 - L6
17 RATIO OF CO. DIFF TO TOT (L16)											CO L16 / TOT L16
18 WINTER PK SYS PLAN PER DIV			870						870		(CO L15/TOT L15) * LESSER (TOT L15 OR TOT L16)
19 WIN PK SYS SHARE-PLN PER DIV			435						435		50% CO L18
20 SUM PK SYS SHARE-PLN PER DIV									435		50% TOT L18 * L17
SUMMER DIVERSITY DETERMINATION:											
21 RATIO-CO. SUMMER PEAKS TO TOTAL PJM SUMMER PEAKS			11.90								CO L1 / TOTAL L1
22 SUMMER PEAK DIVERSITY									462		TOT L1 - PJM SUMMER PEAK
23 ALLOCATION-SUM PK DIVERSITY			55						462		L21 * L22
DIVERSIFIED PLANNING PERIOD PEAKS:											
24 WINTER PEAKING SYSTEMS			5950						5950		L14 - L19 - L23
25 SUMMER PEAKING SYSTEMS									40258		L1 - L20 - L23
26 PJM PLANNING PERIOD PEAK										46208	TOT L24 + TOT L25

Winter peaks increased by 100 MW

DPPP increased by 50 MW

Exhibit JFS-7
3 of 3

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 15-R R-943271 Hbg
5/26/95

Rebuttal Testimony of George T. Jones

Docket No. R-00943271

HA01/27987.1

Q. Please state your name and business address.

A. George T. Jones, Two North Ninth Street, Allentown, Pennsylvania 18101.

Q. By whom are you employed and in what capacity?

A. I am employed by Pennsylvania Power & Light Company (PP&L or Company) as Vice President-Nuclear Engineering.

Q. Please describe your education and professional experience.

A. I graduated from the University of Alabama in 1970 with a Bachelor of Science degree in Mechanical Engineering. I have over 25 years of experience in the operation and design of nuclear power plants. I came to PP&L in September 1991 as Manager-Nuclear Plant Engineering. In June of 1993, I was appointed Vice President-Nuclear Engineering. Prior to joining PP&L, I worked at Entergy Operations where I was general manager of engineering. I also worked at the Tennessee Valley Authority (TVA) as a maintenance engineer, outage director and plant manger. I worked as a design engineer for Combustion Engineering and as a project manager with Fluor-Daniel.

Q. Are you a member of any professional associations or organizations?

A. I am a member of the American Nuclear Society (ANS).

Q. What are your responsibilities as Vice President-Nuclear Engineering?

A. I am responsible for the nuclear engineering functions consisting of engineering design, nuclear fuels and engineering analysis. These functions ensure the design basis, detailed design of the plant, the design control programs, and the configurations management program are adequate to meet the Nuclear Department's commitment to safe, efficient and reliable operation of the Susquehanna plant while adhering to all regulatory and licensing requirements.

Q. What is the purpose of your testimony?

A. My testimony addresses two issues. Section I responds to criticisms of Susquehanna's operating record raised by Complainant Eric Epstein. Section II responds to OCA witness Kahal's characterization of and reliance upon the Strategy 2000 report.

I. Response to Eric Epstein

Q. Complainant Eric Epstein has criticized Susquehanna's operating record. Do Mr. Epstein's comments fairly characterize Susquehanna's operating record?

A. No, they do not. The Susquehanna plant has had an outstanding operating record by any reasonable standard. Mr. Epstein's criticisms are grossly unfair and in many cases simply wrong.

Q. Please summarize Susquehanna's operating record.

A. PP&L has regularly compared the performance of the Susquehanna plant with other nuclear plants in the United States. Susquehanna has always compared quite favorably to the "best plants" in these studies.

One measure of comparison is Susquehanna's score on the Systematic Assessment of Licensee Performance (SALP) conducted by the Nuclear Regulatory Commission (NRC). The NRC has used this performance assessment to determine the level of management attention it must devote to a licensee. The Susquehanna plant consistently has been a top quartile performer in SALP rating since 1986 when the Company began tracking three-year average performance. Both the NRC and PP&L are committed to superior safety performance.

This commitment to safety is part of the Company's belief that safety, quality and performance go hand-in-hand. Generation performance of the Susquehanna plant has been at or near top quartile performance for capacity factor. The annual capacity factor of the Susquehanna plant has exceeded the industry average in every year since 1987. Over this period, Susquehanna's average capacity factor has been 78.4% versus an industry average of 69.9%. Recently, the plant set a world record of 286 days of continuous operation of both units. This ended when Unit 1 commenced a regularly scheduled refueling outage after 427 days of continuous operation.

Q. Do you have any comments on Mr. Epstein's allegations in his testimony?

A. Yes, I do. In his testimony, Mr. Epstein questions the adequacy of elements of fire protection, radioactive waste storage, and the safety of fuel pools at Susquehanna. The identified issues are being fully addressed by PP&L and the NRC. In all of these cases, safety of the plant has been assured.

Specifically, the Thermolag issue raised by Mr. Epstein is an industry wide issue. As he noted, PP&L has taken compensatory actions to assure there is no degradation in safety due to fire protection concerns in the plant. Likewise, disposal of radwaste is being addressed on a statewide and national level. The wastes being generated today at the plant are being handled on site, in full compliance with all NRC regulations, and present no threat to the health or safety of the public. Finally, the Company has dealt thoroughly with the concerns raised about the adequacy of fuel pool cooling. Both PP&L and the NRC have concluded that this issue does not raise any significant safety concern.

The NRC conducts periodic inspections of various licensee activities. After these inspections, the NRC documents its findings and recommendations and also categorizes them in terms of significance. Most of the items that have been characterized as "open" are rectified quickly. Other items are identified as violations which are further broken down into five different significance levels. Most of the violations, particularly in later years of operation, have been Severity Level IV or V, the lowest two categories.

II. Responses to OCA Witness Kahal

Q. OCA Witness Kahal relies, in part, on the Company's Strategy 2000 report to support his conclusion that Susquehanna Unit 2 constitutes "economic excess capacity." Do you agree with his characterization of that report?

A. No, I do not. At the outset, it is important to understand the purpose of Strategy 2000. It is primarily an internal planning document. It is one view of the future and how PP&L and its Nuclear Department might respond to that future. It projects several actions that might be taken to bring Susquehanna costs closer to a projected hypothetical future "market price." Many of the initiatives discussed in the report have been pursued by PP&L in one form or another since the plant began operating in the early 1980s.

Q. Why did PP&L prepare the Strategy 2000 report?

A. The document was created for several reasons. First, the Nuclear Department wanted to study the implications for its operations if some type of a market-driven pricing environment should materialize. Second, the Department wanted to review its existing strategic plan and determine what changes, if any, should be made to that plan to better position the Department for the possibility of a fully deregulated marketplace.

Q. Is Strategy 2000 PP&L's first serious effort to contain costs at Susquehanna?

A. Absolutely not. PP&L has been pursuing a number of strategic planning issues for many years, e.g., 45 day outages, base power uprate, radwaste reductions. Through Strategy 2000 the Company is attempting to identify additional initiatives that will enable it to continue to control and/or reduce costs, and increase capacity factor throughout the next five years. As noted above, PP&L has been performing benchmarking studies since 1986. Even in the face of rising costs these initiatives have enabled PP&L to maintain stable production costs. In fact, since 1986, Susquehanna has remained a top quartile performer in the area of non-fuel operating costs. Strategy 2000 is a road map for continuation of these efforts, not a new revelation.

Q. What about the broad statements in Strategy 2000 that appear to conclude that all of the goals in the study can and will be achieved?

A. Simply put, no detailed cost/benefit analyses has been undertaken to quantify the costs or benefits of the identified initiatives. Some may be uneconomic; others may not be technically feasible. The identified initiatives represent a hypothetical solution to a hypothetical problem, i.e., meeting an assumed market price in the year 2000. It is totally incorrect to suggest that the "savings" preliminarily identified in Strategy 2000 should be factored into any analysis of future projections of rates. Strategy 2000 is a strategic planning document, nothing more.

For example, one of the initiatives in the study proposes to lower the cost per kwh by raising the output of each unit by 80 Mwe through what is described as an "extended power uprate." No BWR has successfully implemented an extended power uprate. The NRC has not approved any BWR for an extended power uprate. In fact, the first step in gaining NRC approval, the completion of Licensing Topical Reports by General Electric, is not scheduled to be completed until later this year. The engineering study to determine feasibility for this work at Susquehanna has only just started. The Company does not know how much it would cost to undertake this uprating and does not have a rigorous cost/benefit analysis at this time.

Another example is the proposal to reduce the time for refueling outages to 28 days on a consistent basis. If this initiative were accomplished, it would reduce replacement power costs; however, the additional costs incurred to shorten the outage and other factors could offset the benefits of these lower replacement power costs. The Company is carefully considering this change and all of the items identified in Strategy 2000. However, as explained above, none of these initiatives should be considered appropriate until a full cost/benefit analysis is completed.

Q. Does that conclude your testimony?

A. Yes, it does.

PENNSYLVANIA POWER & LIGHT COMPANY

STATEMENT 16-R

Hbg JK 5/26/95 R-943271

Rebuttal Testimony of William H. Hieronymus

Docket No. R-00943271

HA01/27945.1

I. Introduction

A. Professional History/Testimonial Experience

Q. Please state your name, business affiliation and address.

A. My name is William H. Hieronymus. I am a Director of the Firm of Putnam, Hayes & Bartlett, Inc. (PHB). My office address is One Memorial Drive, Cambridge, MA 02142.

Q. What is your educational background?

A. I received a B.A. in social science from the University of Iowa in 1965, a Masters degree in economics from the University of Michigan in 1967 and a Ph.D. in economics from the University of Michigan in 1969.

Q. Please outline briefly your occupational history.

A. While completing my graduate studies, I worked for the Institute of Science and Technology on industrial forecasting and for the U.S. Department of the Treasury on business taxation policy issues. Following graduation I was in the U.S. Army. While in the service, my primary assignment was in cost analysis; my duties encompassed cost/benefit analysis, cost forecasting and procurement policy studies. I then joined Systems Technology Corporation, where my primary assignment was economic modelling for the Occupational Safety and Health Administration.

Early in 1973, I joined Charles River Associates as a Senior Research Associate and, later, Program Manager for energy market analysis. My primary responsibility was the direction of studies of supply, demand and price forecasting for electricity and electric utility fuels.

In 1978, I joined PHB. At PHB I have specialized in utility economics, focusing in particular on electric utility planning and regulation. In the last several years, much of my work has involved the design of electric utility restructuring and the analysis of optimal utility management strategies in response to such restructuring. This work has been undertaken on behalf of domestic and foreign governments and utilities.

Q. Dr. Hieronymus, what is the general purpose of your testimony in this proceeding?

A. I have been asked to respond to the capacity testimony filed by Matthew Kahal, on behalf of the OCA, and Paul Metro, representing the Office of Trial Staff. Both witnesses claim that PP&L has excess capacity and propose excess capacity adjustments that would deny PP&L a return on a portion of its generating capacity. Mr. Kahal recommends the exclusion of all common equity return on PP&L's investment in Susquehanna Steam Electric Station Unit 2 (SSES 2); Mr. Metro suggests a 564MW adjustment using a slice of system approach.

Based on my evaluation and analysis, I have concluded that the opposing parties' adjustments are in error and that there should be no excess capacity disallowance in this proceeding.

Q. Have you testified previously in the Commonwealth of Pennsylvania, or other jurisdictions, regarding the appropriate standards for recovering the costs of utility generating investments?

A. Yes. I have testified several times on these matters before the Pennsylvania Public Utility Commission. I testified in PP&L's SSES 1 rate case, Docket No. R-822169, concerning the inclusion of the costs of Susquehanna Unit 1 in PP&L's rate base, and in Docket No.

R-850152, concerning the inclusion of Limerick Unit No. 1 in Philadelphia Electric Company's (PECO) rate base. I have addressed the proper ratemaking treatment of new capacity additions in Docket Nos. R-870732 and R-850267, regarding Pennsylvania Power Company's (Penn Power) need for capacity from Perry Unit No. 1 and the annual net economic benefits provided by that facility. I also testified in Docket No. R-891364, regarding the ratemaking treatment of PECO's Limerick Unit No. 2.

Outside of Pennsylvania, I have discussed investment cost recovery standards at length in several base rate cases concerning newly completed nuclear plants, including Missouri Docket No. ER-84-168 (also filed as Illinois Case No. 85-0006); FERC Docket No. ER-84-560; Arkansas Docket No. 84-249-U; Arizona Docket Nos. U1345-85-156 and U1345-85-367; Texas Case 7460; Illinois Case 87-0043, and New York Case 29124.

Q. Your testimony addresses the need for SSES 2 in terms of the capacity required to meet a reasonable reserve margin. Have you testified previously on the subject of the reserve margins that should be utilized for ratemaking purposes?

A. Yes. This topic was a particular focus of my testimony on behalf of Pennsylvania Power Company in Docket Nos. R-870732 and R-850267 and on behalf of PECO in Docket No. R-8913364, and in Arizona in Docket No. U-1345-85-367. In several other cases, I have discussed standards for determining the need for new generating plant and, in some of them, reached factual conclusions regarding the need for the new facilities that were the subjects of the proceedings.

Q. Your testimony also responds to Mr. Kahal's analysis of the net economic benefits of SSES 2. Have you testified previously concerning the economic net benefit of completed nuclear plants?

A. Yes. In a number of these cases, I sponsored partial or complete analyses of the relative economics of nuclear generation. These cases have included analyses of Limerick Unit No. 1 (Docket No. R-850152), Limerick Unit No. 2 (Docket No. R-891364), Perry Unit No. 1 (Docket Nos. R-870732 and R-850267), and Susquehanna Unit No. 1 (Docket No. R-822169).

B. Areas of Testimony

Q. How is your testimony organized?

A. My testimony is organized in four sections. This section (Section I) provides my background and summarizes my main conclusions. Section II sets forth my interpretation of the relevant regulatory principles that should guide this Commission in dealing with the excess capacity adjustments proposed by the OTS and OCA. Section III analyzes the issue of "physical" excess capacity. Section IV discusses the issue of "economic" excess capacity in the context of Section 1323.

Q. What are your main conclusions?

A. My central conclusion is that all of PP&L's owned and leased capacity is both used and useful and should be fully reflected in rates. Supporting that conclusion are several subordinate conclusions, as follows:

First, there is no disagreement among OCA witness Kahal, Staff witness Metro and PP&L witness Sipics concerning the basic inputs to analyzing the need for PP&L's

capacity, including SSES 2. This agreement encompasses, for example, load forecasts, present and forecast amounts of owned and leased capacity, the amount of QF capacity, and so forth. The dispute among the parties is over what capacity should be included in the analysis and what reserve margin should be utilized in evaluating PP&L's capacity.

Second, both Messrs. Kahal and Metro have improperly included QF capacity in determining whether PP&L has excess capacity. For a variety of reasons stated *infra*, it is clear that QF capacity should not be included in determining whether any of PP&L's owned or leased capacity constitutes excess capacity. Simply excluding QF capacity from their calculations results in a reserve margin of 16.4 percent in 1994/5 and 14.2 percent in 1995/6, which are within the general level of reserves that all witnesses have found to be reasonable.

Third, both witnesses fully <u>include</u> interruptible load at the grossed-up value allowed by PJM in its capacity accounting and fully <u>exclude</u> the effects of capacity credit sales. In my view, the PJM treatment of interruptible load overstates the capacity value that a prudent utility can attribute to interruptible load. Further, I conclude that capacity credit sales are the functional equivalent of PJM-allowed interruptible load. Hence, if interruptible load is to be considered as capacity for purposes of this proceeding, then it should be reflected net of capacity sales. Simply reflecting the capacity credit sales in the calculation would eliminate the excess capacity found by Mr. Metro and Mr. Kahal in the test year and reduce the 371MW of 1995/6 "excess" capacity found by Mr. Metro to 188MW, and the 419MW found by Mr. Kahal to 236MW.

Fourth, I disagree with Mr. Kahal's proposed margin range of 12 to 15 percent. This range fails to account for a number of factual and policy issues which should be addressed in establishing a reasonable reserve margin in a utility rate proceeding. In particular, I dispute Mr. Kahal's conclusion that a 3 percentage point adjustment is a sufficient allowance for the uncertainty and "lumpiness" of plant additions.

Fifth, I disagree with Mr. Metro's analysis of required reserves on two bases. First, I disagree with his original assertion that a reasonable reserve is a single number rather than a range. Second, Mr. Metro's calculation of PP&L's forced outage rate contains a major conceptual error that leads him to mischaracterize the measure of forced outage at the time of peak. Correction of this error shows that PP&L has no excess capacity in the future test year of the year thereafter. It also would eliminate 507MW of Mr. Metro's 564MW adjustment, which is based on an inappropriate nine-year average.

Sixth, Staff and OCA witnesses ignore a number of important considerations that the Commission has stated that it will take into account in determining reasonable reserve requirements. Further, Staff and OCA witnesses' current proposals and methodologies are inconsistent with the approach followed by the Commission in the Company's last rate proceeding. The Commission found that a 22% reserve margin was reasonable in PP&L's last rate case. Applying the calculation procedure relied on by the Commission in that case to PP&L's current situation yields a reserve margin of 17.8%. Under either approach, i.e., using the outcome or the methodology from the last rate case, PP&L has no excess capacity in the test year or the year thereafter.

Seventh, I conclude that an unreasonably strict calculation of allowed reserves provides incorrect incentives to utilities. PP&L could have eliminated or substantially mitigated the disallowances that these witnesses propose. It would be poor public policy to create a strong self interest on the part of regulated utilities that could lead to actions that are inimicable to the interests of customers.

Eighth, I conclude that even if the "economic excess capacity" analysis element of Section 1323 were relevant to this proceeding, which counsel informs me it is not, the analysis discussed by Mr. Kahal and upon which he bases his proposed disallowance is wholly inappropriate. Use of a hypothetical calculation of market prices is totally inappropriate in an analysis seeking to determine the appropriate rate base for rate of return-based revenue requirements. Even were such analysis valid for rate base determination, it would be logically appropriate to use it equally for all rate base assets in Pennsylvania - generation, transmission and distribution, not just one generating plant for one electric utility. Hence, Mr. Kahal's application of a market standard to a single facility is improper, even within the context of the improper standard that he proposes the Commission accept.

Ninth, even if the Commission were to conclude that the economic excess capacity element of Section 1323 is relevant to this proceeding, it should use a contemporaneous coal plant as the comparative basis for determining economic excess. Based on my analysis of SSES 2 costs relative to a 1995 coal plant, I conclude that SSES 2 is not excess capacity.

II. Regulatory Goals and the Policy Implications of Excess Capacity Adjustments

Q. In what context do you believe the Commission should evaluate PP&L's request to recover on a prospective basis the total revenue requirements for SSES 2 and the excess capacity adjustments proposed by the OTS and OCA?

A. Such an evaluation should consider the goals of utility regulation and the nature of the regulatory system as it existed when SSES 2 was planned and built, as well as today's regulatory setting.

Q. What do you believe to be the central goals of utility regulation?

A. The primary goals are fairness to the main participants -- utilities and their investors on the one hand and consumers on the other -- and the promotion of economic efficiency in the production of electricity and/or delivery of electric energy services. An electric utility is a regulated exclusive franchise. In return for the franchise the utility agrees to undertake such investments as are reasonably thought to be required to meet the needs of its customers. It further agrees to submit to a system of rate-of-return regulation in which rates are determined by regulators rather than in the marketplace.

A primary goal of regulation is to assure that the needs of the utility's customers are met. In turn, this requires that the utility be able to attract the necessary capital to meet those needs. Thus, even if there were no direct concern with fairness to investors, customer interests dictate that investors be rewarded properly for the capital invested in utility enterprises. This "capital attraction" function of regulation demands that investors have a reasonable expectation of earning the market required rate of return on funds invested in the enterprise. The shorthand for this principle is that the regulatory process should yield returns that are fair and equitable to investors.

Regulation also must assure that rates are fair and equitable to customers. This requires that utility management operate at acceptable levels of competence and efficiency. This is the "incentive-efficiency" function of regulation; the goal is sometimes stated as providing electric service at the least cost that reasonably can be achieved.

In the period during which SSES 2 was planned and built, and indeed today, U.S. public utility regulation has been based on rate-of-return regulation. Rates are cost based; revenue requirements are based on the recovery of reasonable operating costs plus a return of and on prudently incurred investments. Under rate-of-return regulation, customers, not shareholders, are the primary beneficiaries of particularly fortunate utility investments, and, collaterally, customers also must pay the cost of service connected with prudent investments which turn out to be nonoptimal. It should be noted that the competitive market place exhibits a similar symmetry -- shareholders are the primary beneficiaries of particularly fortunate investments and, collaterally, also must face the economic consequences associated with investments that turn out to be less than optimal.

This description of the nature of U.S. utility regulation as practiced for the past several decades is not a new or unique insight. At about the time of the completion of SSES 2, Dr. Alfred E. Kahn, the noted utility economist and regulator, wrote:

> The essential basis of public-utility regulation is an implicit bargain between consumers and investors that, in exchange for a monopoly franchise, the company accepts the strict legal obligation to serve all customers on reasonable terms.
>
> This means that shareholders accept a return on investment equivalent only to something like the market cost of capital -- the minimum that investors must see a reasonable prospect of earning if they are to put up the necessary funds -- along with the duty conscientiously to anticipate

> the future needs of the public and to make whatever investments may be necessary in order to meet them efficiently. . . .
>
> (Wall Street Journal, 15 August 1985.)

I am fully aware that changes in the basic tenets of regulation are being considered actively and that perceived shortcomings of the existing system are a motive for change. However, as I explain below, these changes should not, and cannot, be considered in this proceeding.

Q. How do regulatory bodies strive to ensure that utility investors receive an adequate return on their investments?

A. Historically, regulators have recognized that in order to provide investors with the incentives necessary to induce them to invest in regulated utilities, those investors must believe that if they wisely undertake investments -- which, by the nature of the technology for electricity generation and transmission, are long-term in both planning and expected project life -- those investments will earn a reasonable return. To provide such assurance, regulators have approved rates that provide investors with their required returns, as long as the projects have been deemed prudent.

Q. What is the role of the used and useful standard in electric utility regulation?

A. The used and useful standard has historically had several meanings. The one most relevant to my testimony in this proceeding derives from the "fair value" system of ratemaking.

The "fair value" system was in common use until the 1940s and still exists in form, but not meaningful practice, in some jurisdictions today. Under fair value ratemaking, investors were entitled to a market return on the fair value of utility assets. That value was determined independent of cost (prudently incurred or otherwise); essentially, it was intended to reflect how much assets would have been worth if the utility were unregulated.

Since the utility was entitled to compensation only with respect to assets that had been "taken" for utility purposes, an element of fair value ratemaking was determining which elements of the investors' property were being devoted to public utility purposes. This property was "used and useful" to customers and defined the limits of property for which compensation at fair market value was required. In this context, regulators sometimes made factual determinations concerning what capacity was not required for public utility purposes by reason of being excess to customer requirements and hence not entitled to fair value compensation.

In recent years some regulatory commissions, including Pennsylvania's, have adopted the excess capacity concept, despite the fact that they are historic cost rather than fair value jurisdictions. These commissions have interpreted the used and useful doctrine as permitting a finding that capacity is excess to the reliability requirements of customers and, based on that finding, have allowed a less-than-full current return on such capacity.

Q. Is there a potential conflict between the excess capacity test and the prudent investment doctrine?

A. Yes, there is. The prudence test looks at causes -- the past decisions of utility management -- and ignores the issue of whether prudent decisions resulted in outcomes that appear optimal in hindsight. Conversely, the excess capacity test, as it is often applied, looks <u>only</u> at outcomes: excess capacity results in a current disallowance even if the decisions that led to high reserve margins were prudent. Thus, the excess capacity test abrogates the implicit compact between regulators and utilities that had previously assured investors of a reasonable opportunity to earn a fair return on their investments.

This conflict between excess capacity penalties and the regulatory compact suggests that regulators should proceed cautiously in adopting excess capacity adjustments. In particular, my testimony will explain that a) capacity not controlled by the utility, and which it could not have reasonably anticipated, should be excluded before the utility can be considered to have excess capacity, and b) regulators should recognize the uncertainties of utility planning.

Q. What do you mean by "the uncertainties of utility planning"?

A. A test for physical excess capacity must recognize that a utility must plan to meet its minimum reserve requirement with a high degree of certainty in the face of quite uncertain load growth. As events of the past 30 years have shown vividly, forecasting loads over the periods of time required to build generating plants is a risky business. In the late 1960s and early 1970s, many utilities found themselves with insufficient capacity. In the late 1970s and early 1980s, load growth was overestimated.

For these reasons, forecasts of reserve margins that must be undertaken at the time construction decisions are made are quite uncertain. If utilities plan to the target reserve margin and if their forecasts are, on average, correct, they will exceed the intended reserve half of the time and undershoot it the other half of the time. As I will discuss later in my testimony, utilities do not, and should not, plan to meet reliability requirements "on average." Prudent planning will result in "excess capacity" when new units come on line more than half of the time. Given the degree of forecasting uncertainty, and the lead times for plant construction, resultant capacity excesses or shortfalls can be substantial.

In addition, in meeting planned needs, the utility cannot economically add capacity in blocks that precisely match annual load growth increments. The lumpiness of optimally sized capacity additions generally will result in shortages or excesses of capacity. At the time SSES 2 was planned and built, the size of plants believed to be optimal was very large.

Q. How should these principles be applied in reviewing the excess capacity adjustments proposed in this proceeding by the OCA and OTS?

A. An analysis of a utility's capacity needs should not be seen as a merely mechanical process. A proper analysis will consider all relevant facts and the need to balance the interests and incentives of both customers and shareholders, in order to reach a fundamentally fair result.

III. Physical Excess Capacity

Q. Please summarize your conclusions regarding the physical excess capacity testimony presented by Mr. Metro and Mr. Kahal.

A. The findings of physical excess capacity by Messrs. Metro and Kahal are in error and should be rejected. Their testimony understates the appropriate reserve margin and overstates the capacity which should be included in determining whether any of PP&L's owned or leased capacity should be considered excess. Moreover, the approach proposed by both witnesses is inconsistent with the Commission's Order in the Company's last rate proceeding. Under any reasonable analysis, PP&L has no physical excess capacity.

A. Commission Requirements for Including SSES 2 in Rate Base

Q. What standard has the Commission previously applied in its review of SSES 2?

A. The Commission did not question the prudence of the decisions that resulted in the construction and operation of SSES 2. In the 1985 PP&L rate case, the Commission applied the used and useful test to SSES 2.

Q. What was the outcome of the Commission's 1985 review of SSES 2?

A. Although the Commission did not question PP&L's prudence with regard to SSES 2, it found that the unit resulted in physical excess capacity for the Company. The Commission was clearly aware that the determination of an appropriate remedy would be complex. In considering its options, the Commission stated that:

> we are mindful that this is an exercise of our discretion and that there are many methods available to us. [citation omitted] <u>In particular, in equitably balancing the interests of shareholders and ratepayers, we must necessarily exercise flexibility and judgement</u>. (emphasis added) (67PUR4th 30, 45)

The Commission determined that the costs associated with operating SSES 2, as well as interest payments and preferred stock dividends, should be included in PP&L's rates, but it denied a common equity return on the investment associated with the unit. The Commission argued that this was a "fair sharing of the burden" of the excess capacity it attributed to SSES 2. The Commission asserted that common equity holders had accepted the risks associated with the SSES 2 investment, but should not be compelled to pay the returns required by the holders of preferred stock and debt.

Q. Did the Commission set any criteria under which PP&L could seek to recover an equity return on SSES 2 in revenue requirements?

A. Yes. The Commission's Order stated that the excess capacity adjustment would be in effect until the Company could "show (1) that for a prospective ECR recovery period, the net benefits from the unit will exceed the net costs of the unit to the ratepayers, or (2) that the capacity from the unit is necessary for system reliability" (emphasis added).[1] The first of these criteria is not addressed by any party and, as Mr. Kahal properly observes, the purpose of this economic element was to allow economic benefit to mitigate a finding of physical excess capacity. Hence, I will focus on the physical excess capacity, or "need" branch of this test.

Q. What is your understanding of the test for physical excess capacity, as it has been applied by the Pennsylvania Public Utility Commission?

A. The Commission has outlined an analysis of physical excess capacity as involving the *following process: (1) determine a reasonable reserve margin; (2) specify which plants or*

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[1] 67 PUR4th 30, 45.

parts of plants are to be counted in computing installed or available capacity; and (3) determine whether all the installed or available capacity is needed to meet the utility's peak customer demand plus a reasonable reserve margin in the relevant time period. The remainder of Section III addresses these three issues.

B. System Reliability and the Calculation of an Appropriate Reserve Margin

Q. Should the physical excess capacity test simply encompass an examination of the capacity required to maintain system reliability on an engineering basis?

A. No. The physical excess capacity test is undertaken in the context of a regulatory proceeding -- specifically, a rate case in which the issue is whether some part of the utility's capacity should be excluded in whole or part from rate base. A finding of excess capacity that results in such an exclusion is contrary to the normal right of investors to receive a return on resources devoted to the public service. In previous proceedings of this Commission, I have testified regarding my concern with using after-the-fact tests of outcomes, such as lower levels of load growth than were reasonably foreseen at the time that investment decisions were made, as being violative of the prudence standard that has been the core of the regulatory compact for decades. I recognize, however, that the Commission has determined that tests of excess capacity are warranted and that rate base adjustments can be an appropriate result when excess capacity is found.

Despite this general determination that revenue requirements can reflect a finding of excess capacity, the Commission has not relied on a simplistic engineering-based reserve criterion. The end result has been that, in most instances, the Commission has established a reserve margin for rate making purposes well in excess of engineering minimums. A prime example of this was PP&L's 1984 rate case, where the Commission utilized a reserve level of 22 percent.[2/]

Q. Has the Commission provided guidance concerning what factors should be taken into account in determining an appropriate reserve margin?

A. Yes. The Commission has viewed the test for physical excess capacity as a test that is applied on a case-by-case basis, with a broad range of factors deemed relevant to the individual situation. These factors have extended far beyond simple annual reserve margin calculations. Factors referenced in previous recommended decisions and final orders have included:

1. The utility's need to anticipate new capacity requirements and to plan in a manner intended to ensure reliable service;
2. The difficulty of adding capacity on an as-needed basis, implicitly recognizing the uncertainties inherent in both load forecasting and other aspects of long-range capacity planning;
3. The inevitability of temporary bulges in capacity when capacity additions enter service when they are needed;
4. The age of plants, recognizing that older plants may experience increased mechanical failures or are frequently subject to severe restrictions as a result of new environmental regulation;
5. The impact of sales and purchases and buy/sell arrangements on capacity needs and rates;

2/ 67 PUR4th 30, 43; Gruber direct, R-842651, p. 3.

6. The potentially limited usefulness of reactivated older plants and newly constructed peaking facilities in meeting capacity needs;

7. The potentially limited usefulness of plants held in cold reserve in meeting capacity needs; and

8. The impact of sudden, dramatic losses of load (such as the loss of large industrial customers) that were not foreseeable on current capacity/need balances.

These criteria demonstrate recognition of several considerations that are appropriately taken into account:

a) Utilities are not omniscient and should not be held to a standard of perfection in planning to meet reliability obligations.

b) Capacity cannot economically be added in sizes that fit annual load increases. While this problem is less acute today than previously, it was a very real fact when SSES 2 was planned and constructed and, indeed, when it was completed. Since it is SSES 2 that is at issue in this proceeding, these are the facts that are relevant.

c) The establishment of a reserve margin should take into account the characteristics of the plants available to the utility, particularly, their reliability. Mr. Sipics has discussed reliability issues concerning both the QF *capacity and interruptible load. Mr. Krall has explained that the future* operation of PP&L's coal units is in doubt due to new environmental requirements.

d) The impact of sales and purchases must be taken into account. All parties have taken into account PP&L's firm off-system sales. However, the OTS and OCA propose to take into account NUG purchases and ignore PJM capacity credit sales.

e) There are specific issues relating to winter peaking utilities that should be taken into account. Mr. Sipics has testified concerning the problems of meeting reliability within PJM, particularly with the variance of load and capacity availability in the winter.

Q. You have discussed various matters which the Commission has stated should be taken into account in determining the need for capacity and an appropriate reserve margin for ratemaking purposes. Do you agree that these should be taken into account?

A. Yes, I do.

Q. Is there a commonly-used starting point for examining the reasonableness of a utility's forecast reserve margins?

A. Yes. Often, the Commission and witnesses appearing before it have referred to the minimum capacity requirement imposed by the power pool to which the utility belongs. But, as indicated by the discussion above, the pool requirement should be considered only as a starting point for establishing a reasonable reserve margin for regulatory purposes.

Q. *How is the pool-imposed minimum for PP&L calculated?*

A. PP&L's minimum for 1994-95 is 12.0 percent over its winter peak, a figure derived according to the PJM methodology. The PJM calculation uses the system-wide required reserve in summer (22 percent in 1994/95), and incorporates adjustments based on utility-specific characteristics such as forced-outage history, the prevalence of large units and load-drop ratios. Because PP&L is a winter-peaking company, its calculated PJM capacity obligation (7217MW, summer rating, or 22.3 percent above the Company's diversified planning period peak) is typically converted to equivalent winter megawatts and compared to its winter peak. This conversion has been detailed by PP&L witness Sipics. The conversion results in a 1994-1995 required reserve for PP&L of 7361MW (winter rating), or 12.0 percent over the forecast winter peak of 6575MW.[3/]

Q. Is this level of winter reserves the appropriate maximum reasonable reserve level for PP&L?

A. Absolutely not, and the Commission has agreed. As I have noted, in 1985, when PP&L's PJM margin was about 11 percent of its winter peak, the Commission utilized a reserve margin estimate of 22 percent.

Q. You have testified that in its capacity planning, a utility should err on the high side in planning to meet reliability requirements. Why is this so?

A. Utilities should view the minimum requirement as exactly what it is -- a minimum, and not the expected value of a prudent reserve margin. A prudent utility will plan its capacity to meet its load at the underlying PJM reliability standard of one-day-in-ten-years. If it merely plans to meet expected load with expected resources, that standard will not be met.

It also must be noted that the three components affecting resources needed by PP&L to meet a PJM minimum (load level, resources and the minimum itself) are highly uncertain. Understandably, the PP&L forecasts relied on by PP&L, OTS and OCA

[3/] As explained by Mr. Sipics during cross-examination, these figures from Response to OTS RB 53 are slightly different from those in Exhibit JFS-1 because the response is based on 1992 forecasts for 1994-1995, while the exhibit data are based on PP&L's most recent forecast for 1994-1995.

witnesses all show smooth load growth, no change in the 12 percent requirement, and no unplanned loss of capacity, including interruptible load. Yet each of these components is far from certain. Load growth is forecasted in a narrow range with little year to year fluctuation over the next decade, averaging only about 130MW per year. However, load growth is far less constant and predictable than this. On a year-to-year basis, this figure can and has been materially exceeded. For example, PP&L's winter peak demand increased by 313MW between the winters of 1990/91 and 1992/93, and by 273MW between 1992/93 and 1993/94.[4/]

The PJM requirement is also sensitive to PP&L's forced outage rate, maintenance requirements and scheduling, seasonal diversity, and so forth; the forecast of constant requirements could well be in error. Putting these two considerations together can result in a material increase in requirements. Hence, while PP&L is predicting an increase in PJM requirements of a relatively constant amount, averaging less than 150MW per year, in the two-year period 1990/1 and 1992/3 its installed capacity obligation increased by more than 900MW.

Capacity also is uncertain. I have noted that several of PP&L's units are beyond normal expectations of their technical lives. In addition, the amount of interruptible load, assumed constant at a PJM credit value of 345MW, also is clearly uncertain. PP&L is proposing to reduce the interruptible credit, or discount, to more nearly reflect the capacity value of interruptibility. Further, as PJM as a whole moves more closely to capacity balance, interruptions are likely to become more frequent. The decrease in the discount received by interruptible customers and the increase in the costs they incur could easily reduce the amount of available interruptible resources by a significant amount. Since

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4/ 1994 Annual Report, p.45.

PP&L's interruptible tariff arrangements are annual, the Company will have little of this resource if customers move off the rate or reduce their amount of interruptible load.

Further, the high cost to the customer arising from loss of load, and the fact that in extreme circumstances an insufficiency of a relatively small amount of capacity (relative to the size of the pool) can cause collapse of the grid, as happened in 1966 in the Northeast blackout and more recently in California, mean that customers benefit from this conservativism. A landmark study commissioned by the Electric Power Research Institute (EPRI)[5] highlights the asymmetry between costs associated with planning for capacity below a least-cost range and the costs of planning for capacity above that range.

> Significantly, the cost of planning for a reserve margin less than the least-cost range can exceed greatly the costs of planning for a reserve margin at the same increment greater than the least-cost range. This is because costs to consumers of outages and increased gas- or oil-fired generation resulting from insufficient capacity at low reserve margins tend to outweigh small increases in the cost of electricity from extra capacity.
>
> The results of this study imply that while no amount of analysis and debate can determine precisely the best planning reserve margin within a wide least-cost range, it is nevertheless crucial to avoid planning reserve margins that are too low. (emphasis added) (p.S-9).

PJM recognizes that even a prudent utility may occasionally find itself short on capacity, and while it allows utilities to purchase capacity to alleviate such temporary situations, it also forbids utilities from consistently relying on such purchases to fulfill their capacity obligations.[6] In other words, a utility cannot count on fulfilling only its bare minimum requirement and "living off the grid" if its load growth forecast proves to be too

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5/ Costs and Benefits of Over/Under Capacity in Electric Power System Planning, EPRI Project 1107, October 1978.

6/ *See* Pennsylvania-New Jersey-Maryland Interconnection Agreement, Composite Text, Article 6.2.

low. Thus, even the pool does not expect its members to plan only for the required minimum, but encourages them to be prepared to satisfy somewhat higher electricity demand, since penalties are levied if a utility fails to meets its PJM obligation.

In addition, I believe that it is important to note that over the last eight years, during which PP&L has had reserve margins (inclusive of QF capacity) that have been well above 12 percent of peak load percent, and PJM as a whole has had capacity in excess of its planning criterion, PJM has experienced nine loss-of-load incidents: seven voltage reductions and one set of two rolling blackouts.[7]

Q. Are there other factors which should be considered in establishing a reserve margin in a rate proceeding?

A. Yes. One major additional factor is the indivisibility of capacity, which has been referred to as the "lumpiness" problem. SSES 2 is, as were most nuclear units of its vintage, a large unit, with more than 1000MW of capacity. Bringing such a unit on line inevitably will result in a large increase in reserves. While off-system transactions can, and have, mitigated this increase to some extent, the problem remains.

No party is arguing that the decision to build SSES 2 was imprudent. Hence, in a rate case considering whether SSES 2 results in excess capacity, it is the size of SSES 2 that ought to govern the allowance for lumpiness.

Without SSES 2, PP&L would not have adequate capacity under any standard proposed in this case. Indeed, without SSES 2 PP&L would only have 7244MW of available resources, which would not be sufficient to meet its PJM minimum installed capacity obligation for the future test year.

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[7] Sipics cross-examination, p.271.

Q. How has the Commission viewed the PJM minimum in previous cases?

A. While the Commission clearly uses the PJM minimum as one measure of an appropriate reserve margin, it has not used it as the <u>only</u> measure. In fact, it has, at times, approved a margin considerably higher than the PJM minimum.

I have mentioned that in the 1984 SSES 2 rate case, the Commission Staff's recommended reserve margin was 22 percent and the Commission accepted this recommendation. This calculation was based on PP&L's history of forced outages in the late 1970s and early 1980s.[8/] I have replicated this methodology using readily available PP&L forced outage data to calculate a recommended reserve margin that would be applicable to the current situation. The five-year rolling average forced outage rate for 1990 through 1994 was 8.9 percent. Applying Mr. Gruber's method would yield a reserve margin of 17.8 percent.[9/]

Implicit in the Commission's approval is the recognition that the PJM minimum can only be thought of as the lower bound for a reasonable reserve. Various parties to PP&L previous rate cases, including OTS, have also recognized that reserves well in excess of the PJM minimum are reasonable.[10/]

8/ 67 PUR4th 30, 43; Gruber direct, R-842651, p. 3.

9/ Based on 1990-94 average of the three-year rolling averages reported to PJM for those years (8.9 percent), multiplied by two.

10/ In the 1984 SSES 2 proceeding, the Lehigh Valley Power Committee suggested a reserve margin of 20 percent (Baron direct, R-842651, p.5). In the Susquehanna Unit No. 1 rate case in 1983 (Docket No. R-822169, Susquehanna 1), the PUC staff proposed a margin of 29.6 percent (Gruber direct, p. 3).

Q. Given the above discussion, what reserve margin do you consider reasonable for use in this proceeding?

A. Because it is difficult to precisely quantify the impact of the factors I discuss above, I believe that it is appropriate to view the required reserve margin as falling within a range. Mr. Sipics has estimated that a reasonable range for PP&L is bounded at the bottom by the 12 percent PJM minimum and extends to at least 20 percent. I note that these figures are below the 22 percent margin accepted by the Commission in the last rate case.

I have noted that uncertainty about PJM reserve requirements and load growth dictate a significant margin above the requirement based on "expected" load growth and PJM margin. I have also noted the uncertainty concerning some of PP&L's resources, which also would lead a prudent utility to plan for reserves in excess of the PJM minimum. These types of uncertainties can cause PP&L's capacity obligation to be more than 5 percent above the PJM minimum, as outlined by Mr. Sipics.

The other major factor is the indivisibility of capacity, which has been referred to as the "lumpiness" problem. SSES 2 is, as were most nuclear units of its vintage, more than 1000MW. Bringing such a unit on line clearly will result in a large increase in reserves. While off-system transactions, can, and have, mitigated the situation somewhat, the impact of this large baseload capacity block remains.

No party is arguing that the decision to build SSES 2 was imprudent. Hence, in a rate case considering whether SSES 2 results in excess capacity, it is the size of SSES 2 that ought to govern the allowance for lumpiness.

Without SSES 2, by any measure, including those used by OCA and OTS witnesses, PP&L would not have adequate capacity. Furthermore, SSES 2 capacity has been necessary for meeting PP&L's PJM installed capacity obligations over the last several years. Hence, PP&L is not seeking full rate base recognition of SSES 2 the first year that some portion of it is needed to meet capacity obligations.

Using Mr. Kahal's severely understated lumpiness adjustment of 3 percent in conjunction with Mr. Sipics 5 percent adjustment for PJM after-the-fact accounting results in at least an 8 percent range above the PJM minimum.

Q. Mr. Kahal proposes a reserve margin range of 12 to 15 percent. Is this appropriate?

A. No. His range fails to reflect the various factors discussed above, and is inconsistent with the reserve margin used by the Commission in past PP&L rate proceedings. Indeed, the only adjustment he makes is for the "lumpiness" issue, and even here his adjustment is seriously understated. Specifically, he allows only a 200MW (3 percentage points) "cushion" based on his assertion that capacity <u>currently</u> is added in blocks of 100-300MW.

While block sizes have become smaller as new capacity has shifted to gas-fired combustion turbine or combined cycle units, this fact is irrelevant. This case is not considering whether a new 200MW gas unit creates excess capacity. It is about whether SSES 2 creates excess capacity, and SSES 2 is not a small gas unit. Indeed, the small gas technology now in vogue was not available when SSES 2 was planned or completed.

Mr. Kahal accepts that in earlier times -- the period when SSES 2 was planned and built -- large units were the commonplace capacity additions. The logic of his position is that a reasonable range at that time would have spanned the lumpiness caused by large units. His use of a smaller range today suggests a "reasonable range" that varies with time and with technology. If this is the case, then the "reasonable range" in a rate case considering a large unit that was prudently built should be chosen with reference to the lumpiness inherent in such units.

Q. OTS Witness Metro asserted in his direct testimony that a reasonable reserve margin is a single number, not a range. What is your assessment of this argument?

A. While Mr. Metro's direct testimony appeared to propose a target reserve margin based on a single figure, I interpret his answers during cross-examination as recognizing that a range is appropriate. See Tr. 1512.

Q. Mr. Metro's calculation of PP&L's reasonable reserve margin requires an adjustment for forced outages. Have you reviewed the forced outage calculation?

A. Yes, I have.

Q. Is that calculation performed properly?

A. No, it is not. Mr Metro's adjustment is 250MW for 1995/6, growing to 291MW as the capacity being sold off system returns to native load use. He states that this adjustment is motivated by the fact that forced outages are experienced at times of peak load. In reviewing his testimony, I was struck by the fact that the 250MW allowance is only 3.2 percent of the generating capacity that he uses in calculating PP&L's resources. I know of no utility whose forced outage rate is that low. In PP&L's case, the most recent three-year rolling average forced outage rate used by PJM in setting its reserve requirement is 9.7 percent.

A review of Mr. Metro's exhibit demonstrates the source of his error. He took lost generation due to forced outages and divided by 8760 hours to derive an hourly average generation lost because of forced outage. However, this is not a measure of forced outage at the time of peak. Units that are not called to run do not have forced outage-related lost generation. During non-peak periods, much of the generation that will be required at peak times is not called to run and hence has no lost generation. Thus, a calculation of the average hourly forced outage rate over all hours of the year will systematically and substantially understate forced outage rates pertinent to peak hour operation.

Q. Do you have an opinion as to the proper estimate of forced outage rates for peak hours?

A. Forced outages are essentially random. Barring some specific and unusual circumstance for PP&L, the annual forced outage rate (9.7 percent in the most recent PJM calculation) is the best estimate for peak hour forced outages.

Q. Do you have any other criticism of Mr. Metro's forced outage rate calculation?

A. Yes. The data on which he relies includes lost generation only for PP&L's owned and leased capacity. Implicit in his use of the calculation is the assumption that QFs never have forced outages. This, of course, is incorrect.

Q. If you were to recalculate Mr. Metro's forced outage allowance based on a 9.7 percent forced outage rate, what would the effect be on his excess capacity finding?

A. Computing 9.7 percent of 1995/6 capacity (including the NUG capacity that he proposes be included as capacity) yields an adjustment of 757MW, rather than the 250MW that he has used. The additional 507MW more than eliminates the 371MW of excess capacity that he asserts exists in that year. I also would note that the correct application of Mr. Metro's forced outage adjustment, in combination with PP&L's 12% PJM minimum reserve requirement, produces an reserve margin of approximately 23 percent -- essentially the same value as Mr. Gruber found in the prior SSES 2 case.

C. Calculating available capacity

Q. In the context of this proceeding, how should the Commission measure PP&L's available capacity?

A. In a used and useful determination, the Commission should evaluate the capacity that is owned, leased or otherwise controlled or voluntarily acquired by the utility. Therefore, the proper measure of available capacity should consider all owned or leased generating units. It should include non-utility generating capacity only to the extent that such capacity was contracted for as part of the utility's plan to meet its obligation to serve <u>its</u> customers. In addition, available capacity should be reduced to take into account the impact of known firm capacity sales. Moreover, under some circumstances, it should take into account the impact of load management programs and capacity credit sales.

1. Appropriate treatment of QF capacity

Q. Should a determination of whether SSES 2 creates excess capacity take into account PP&L's QF contracts?

A. No. A regulatory inquiry that has as a possible outcome a disallowance of return on prudent investments surely must not penalize the utility on the basis of capacity that was added involuntarily and was added after its own capacity commitments had become irrevocable (indeed, after its last unit was completed). I recognize that the Pennsylvania PUC regards "used and useful" as a standard separate from prudence. Nonetheless, it would be patently unreasonable to deny a return on otherwise needed plant solely on the basis that PP&L had obeyed federal law and the regulations of this Commission requiring it to purchase output from QFs which it did not and does not need. Not only would such a policy be unreasonable, it would be confiscatory. It also would give the utility clear incentive to minimize the amount of QF capacity on its system regardless of other economic and policy considerations.

PURPA did not become law until 1978. Its role in opening up the market to large amounts of non-utility generation, as has occurred, was not anticipated. Moreover, it was not until its validity had been tested in the courts and FERC had issued implementing regulations, in the early 1980s, that developers began to build any appreciable QF capacity. By this time, SSES 2 was substantially completed. Hence, PP&L could not reasonably have anticipated the imposition of large amounts of QF capacity and modified its plans accordingly.

In PP&L's case, there are other reasons that the QFs should be excluded from the Company's available capacity measure. First, the QF contracts were finalized after the last substantial PP&L capacity expansion -- the addition of SSES 2. Assuming arguendo that PP&L has any excess capacity, the QFs are clearly the cause of that excess. Since PP&L had no choice but to purchase QF power, and the Commission accepted contracts based on PP&L's energy only avoided costs, the only equitable solution is to exclude QFs from an examination of PP&L's capacity in this rate case proceeding.

Second, the Commission itself recognized that PP&L did not need additional capacity for reliability purposes. Since the Commission itself has recognized that PP&L would not have needed to undertake a voluntary capacity expansion, it would be grossly unfair for the Commission to now penalize it for an expansion it did not undertake and would not have undertaken.

Q. Have you reviewed the testimony of Messrs. Kahal and Metro on whether QF capacity should be included in an excess capacity calculation?

A. Yes. Both witnesses argue that QF capacity should be considered as PP&L capacity.

Q. What are your criticisms of Mr. Kahal's analysis of QF capacity?

A. Mr. Kahal has oversimplified the nature of the excess capacity adjustment and misinterpreted the Section 1323 discussion of QFs.

First, Mr. Kahal argues that an excess capacity adjustment "deals with the fact of excess capacity, not with whether the utility has acted imprudently". I already have responded to that conclusion, and will amplify my criticism based on the incentive consequences of this proposed policy below.

Second, Mr. Kahal notes that Section 1323 precludes the Commission, in its used and useful determinations, from including QF capacity that was "contracted for within three years after the utility's base load unit enters service and for a five-year period thereafter". However, he then appears to leap to the conclusion that this section also mandates the inclusion of QFs after the expiration of the five-year waiting period. This simply is incorrect. Section 1323(c) establishes a discrete time period in which the Commission cannot include capacity in determining whether a utility has excess capacity. It does not indicate that QF capacity must be included after those dates expire.

Q. What elements should the Commission consider in deciding whether to extend the exclusion period for QFs capacity?

A. The Commission should examine whether the utility could have reasonably foreseen the imposition of the PURPA requirements at the time it undertook the capacity expansion in question. The logic of the legislature's position is that the utility should not be penalized for its own capacity construction by virtue of purchasing QF output. The eight-year window allowed would, under most circumstances, protect the utility from an inappropriate excess capacity disallowance resulting from its compliance with PURPA. I interpret the time-limited nature of the protection as meaning that the Commission is entitled to use QF capacity to disallow costs when the utility blatantly disregards likely QF capacity and over-builds its system. By 1986, it had become clear that cogeneration that could be "put" to the utility was quantitatively significant and an important fact for utilities to take into account in capacity planning. PP&L clearly has not disregarded likely amounts of QF capacity in its post-1986 capacity planning. Indeed, other than the highly cost effective Susquehanna uprate, it has added nothing to owned or leased capacity since that time. Hence, the logic of the legislation, when applied to PP&L's circumstances, dictates that the QF capacity should be ignored for purposes of a "used and useful" determination.

Finally, it must be emphasized that the Commission has specifically recognized that PP&L did not need QF capacity and approved energy only payments in each of PP&L's QF contracts. To count QFs in determining whether PP&L has excess capacity would be inconsistent with these prior Commission orders.

Q. Mr. Metro lists five reasons why he believes QF generation should be included in PP&L's capacity calculations. Do you agree with his reasons?

A. No, I do not. His first reason is that "Federal Law requires electric utilities to purchase power from NUGs." He gives no reason why this supports his conclusion. I believe that, to the contrary, the fact that QF power must be purchased whether needed or not supports my belief that it should be excluded for purposes of a "used and useful" inquiry concerning capacity that economically could not have been cancelled in favor of reliance on QFs.

His second reason is the assertion that QF capacity is as reliable as PP&L's own generation. Even if true, this is irrelevant because the issue is not the availability of QF energy, but the nature of the capacity it represents.

Third, he asserts that utility planning is inherently risky: "whether PP&L had bad timing and luck with the development of Susquehanna 1 and 2 or whether PP&L had poor planning and vision toward the development of QF generation, the result of PP&L's action and/or inaction lies solely with PP&L and its shareholders." He makes no specific claim for "poor planning and vision toward the development of QF generation," nor could he. As I have indicated, QFs only became a meaningful prospect when Susquehanna was already very nearly complete. The statement that the results of PP&L's action lie solely with it and its shareholders denies all of the fundamental tenets of utility regulation. Mr. Metro's statement is an entirely incorrect characterization of regulation.

His fourth reason is that QF power is used. For the reasons I have discussed in connection with his second reason, this is irrelevant.

His fifth reason is that QF power is recognized as a resource by PJM. It is interesting to note that if PP&L did not report QF power as a reliable resource, then it would not be recognized. Hence, this "reason" would severely penalize PP&L for declaring QFs as capacity and taking advantage of it for PJM capacity calculation purposes. In any event, as with his second and fourth reasons, the fact of QF capacity is not at issue. For the reasons I have discussed, and that the Commission itself has discussed in earlier dockets, QF capacity that has been forced on PP&L by law and regulation should not be used to deny otherwise valid full inclusion of its own, pre-existing capacity in rate base.

2. *Appropriate treatment of interruptible load*

Q. How should interruptible load (IL) resources be considered in reserve calculations?

A. Because interruptible resources are not wholly controlled by the utility, they should not be considered as precisely equivalent to actual installed capacity. Their availability is subject to uncertainty that has nothing to do with the engineering constraints the utility faces in its own plants. Furthermore, interruptible customers represent a limited capacity resource when compared to utility generating capacity such as a peaking unit. PP&L's current interruptible contracts specify that customers are only required to interrupt a maximum of ten times per year, up to a maximum of ten hours per interruption. In contrast, peaking units can be called upon to operate whenever they are needed (subject to relatively low forced outage rates).

These concerns notwithstanding, PJM procedures treat interruptible load as 100 percent firm and hence requiring no reserves. That is, a MW of interruptible load is actually treated as being worth more than a MW of actual plant. While I believe that this overstates the value of interruptible load, I will use this same convention in my calculations. However, I note that the PJM calculation is inherently short term. There are intermediate and long term issues affecting the value of interruptible resources that would not be reflected in the PJM treatment.

Q. What are these intermediate to long-term issues?

A. PP&L interruptible customers <u>choose</u> to take part in the program. PP&L has not been able to control the choice to participate or the level of participation, and therefore cannot predict exactly what level of IL resources will be available in the future. Many elements can affect a customer's participation. Even a change in a company's business that has nothing to do with the interruptible program -- say, the installation of high-technology equipment with great sensitivity to changes in electricity supply, or the arrival of a new and highly risk-averse manager -- could change a customer's willingness to remain in the program, and because virtually all IL agreements are short-term (one year), it is quite easy for a customer to shift a portion or all of its interruptible load to firm service. A decrease in the discount given to interruptible customers could induce them to move to firm service. In fact, a reduction of approximately 50 percent in the interruptible credit has been proposed by PP&L in this proceeding to better reflect the cost and value of interruptible service. Similarly, more frequent interruptions as PJM moves closer to balancing loads and resources are likely to discourage at least some customers from renewing their contracts.

Clearly, IL availability depends on economic factors that determine an IL customer's willingness to accept interruption at any point in time and its participation over periods longer than the one-year duration of its agreement. These considerations, which are independent of engineering constraints, limit the extent to which IL resources should be considered equivalent to generating capacity. In addition, because customers can refuse to be interrupted in some circumstances, there is no way to ensure the availability of a given level of interruptible load.

Q. Do you argue that interruptible resources should be excluded from a physical capacity assessment?

A. No, not necessarily. But it should be recognized that there is some uncertainty attached to the availability of IL resources, and that consequently their contribution to capacity availability is overstated. Mr. Kahal has, in fact, acknowledged this in a report filed in a different proceeding, where he noted that there is "a possible degradation to reliability from increased reliance on load management"[11] (e.g., interruptible customers).

Q. Have you included PP&L's interruptible load resources in your analysis?

A. Yes, I have. I should emphasize that doing so is a conservative approach -- i.e., one that increases PP&L's calculated reserves. However, I believe that if interruptible load resources are fully included, they should be offset by PP&L's capacity credit sales.

Q. Why do you believe that capacity credit sales should be netted against interruptible load for the purposes of an excess capacity determination?

A. The principal economic value of interruptible load to PP&L and its other customers is that it contributes to meeting PP&L's PJM installed capacity obligation. But, what is the monetary value of having capacity to meet the PJM capacity obligation? It is the ability to avoid buying capacity in the capacity credit market (if PP&L is short of its obligation) or the ability to make additional sales into that market (if PP&L is long on capacity relative to its obligation). From a short term perspective, these capacity credit transactions have the same effect (but in the opposite direction) as interruptible load (once the grossing up of interruptible load for reserves is taken into account).

Of course, when one is adding up resources that count against PJM capacity requirements, capacity credit sales must be netted off against total available capacity, with no need for specific assignment to interruptible load as I have suggested. Indeed, since Mr. Metro and Mr. Kahal are simply adding up capacity without regard to differences

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11/ "A Need for Power Review of Delmarva Power and Light Company's Dorchester Unit 1 Power Plant, March 1993, p.II-8.

between capacity for PJM accounting and calculations pertinent to this case, they should be netting capacity credit sales from their calculations.

Q. Mr. Kahal has characterized capacity credit sales as "paper" transactions, and argues that they should not be included in an examination of capacity. Do you agree?

A. No. Capacity credits are treated the same as actual physical capacity by PJM, when it evaluates a utility's available resources relative to that utility's capacity obligation. I would also note that in previous testimony, Mr. Kahal has referred to a utility's capacity credit purchases as "available resources,"[12] suggesting that he is willing to recognize their validity as capacity resources for the utility that is purchasing the credits.

3. *Incentive effects*

Q. Do you have any other comments that you wish to make concerning the approach used by the OTS and OCA witnesses in assessing the need for PP&L's capacity?

A. Yes. I simply would like to note that adherence to simple calculations of after-the-fact reserve margins for determining whether PP&L is entitled to be paid for its owned and leased capacity could create adverse incentives. If a utility had believed over the past decade that it was going to lose a great deal of money for every megawatt of "capacity" that it created, it would have had a powerful incentive to minimize the amount of additional capacity on its system regardless of other economic or policy considerations. Decisions regarding QF contracts, load management and unit uprates would have been scrutinized

[12] "An Economic and Need for Power Evaluation of Baltimore Gas and Electric Company's Perryman Plant," May 1991, p.II-15.

from that perspective. In fact, the utility likely would have sought methods of reducing *capacity reserves including plant retirements and load growth.*

The OTS and OCA witnesses claim disinterest in why reserves are what they are, and look only to whether the achieved reserve margin fits into a narrow range above the PJM minimum. I do not believe that this is or should be viewed as an appropriate public policy for Pennsylvania.

D. Analyzing PP&L's physical capacity needs

Q. Based on your analysis of PP&L's capacity and a reasonable reserve margin, do you have an opinion as to PP&L's physical capacity needs?

A. Yes. It is clear that PP&L has no physical excess capacity. Exhibit WHH-1 shows capacity and projected load for the ten years beginning with 1994/5. I have shown the ten year period to conform to the exhibits of witnesses Sipics and Metro. I do not mean to imply that the Commission necessarily ought to utilize 10 years of data. I have based this exhibit on Mr. Sipics' inputs regarding the amount of load and resources.

Consistent with my testimony, I have excluded QFs, included interruptible load, and have offset part of interruptible load in the first two years by including the impact of capacity credit sales. Due to the short lead time for such sales, I have not included any offset sales after 1995/6. This almost certainly is a conservative assumption that will overstate reserves in subsequent years.

As is shown on the Exhibit, PP&L's reserve margin for ratemaking purposes is 7.5 percent in 1994/5 and 11.5 percent in 1995/6. In subsequent years, as sales to other utilities unwind, the margin grows somewhat, peaking at just under 20 percent in 2000/1. This table clearly demonstrates that PP&L has no physical excess capacity in the future test year or the year thereafter. Nor does PP&L have any physical excess capacity during the five-year period 1996-2000, when the sale of capacity to JCP&L returns to the PP&L system.

Q. Mr. Metro finds that 564MW of PP&L generation capacity is excess to his definition of a reasonable reserve margin. Assuming, hypothetically, that the Commission were to accept his calculation of a reasonable reserve margin, would this finding of excess capacity be warranted?

A. The 564MW finding is based on an average over nine years. The calculation is dominated by the return of capacity presently being sold to other utilities. I presume, therefore, that his nine-year measure of capacity is dependent on his acceptance of PP&L's proposal to flow the cost of this returned capacity back through the ECR. If the Commission does not accept the ECR proposal, the nine-year measure he has adopted should not include the returning capacity. Without such capacity, he would have found no excess capacity in the nine-year period, even using his own reserve margin standard.

Q. You find that PP&L has no excess capacity on its system. How does this conclusion compare with the OCA and OTS witnesses' findings in this case, and with previous Commission rulings?

A. First, it is important to recognize that Mr. Metro's and Mr. Kahal's conclusions are almost wholly dependent on their inclusion of the PURPA-mandated QFs in the capacity measure. If QF capacity is excluded from the capacity calculation, PP&L's reserve margins in the test year and the year thereafter are 16.4 and 14.2 percent, respectively -- very close to the *improperly low reserve margins the witnesses themselves advocate. Its margins in the* later years are not significantly higher than the witnesses' recommended levels.

Second, on the basis of the 22 percent reserve margin applied by the Commission in the last PP&L rate case, PP&L has <u>no</u> excess capacity throughout the period examined by Mr. Metro and Mr. Kahal.

Third, by applying the general methodology accepted by the Commission in the last PP&L rate case, PP&L's reasonable reserve margin is 17.8 percent; under this measure, PP&L has no excess capacity in the future test year.

Fourth, even taking the opposing parties' positions at face value, they find that a significant part of SSES 2 is needed and is therefore not excess. As I have discussed, SSES 2's size was standard for baseload plants being built in the 1970s and 1980s, and it would be inappropriate to penalize PP&L shareholders for a proper and prudent undertaking.

These factors, individually and as a group, are further support for my finding that PP&L's system has no physical excess capacity.

IV. The Economics of SSES 2: Section 1323's Physical and Economic Excess Tests

A. Introduction of Section 1323 and its Application to SSES 2

Q. Why have you analyzed SSES 2 under the requirements imposed by Section 1323?

A. I have undertaken this analysis to respond to the arguments made by OCA. It is my understanding from counsel that the proper ratemaking treatment of SSES is governed by the Commission's 1985 Order, and consequently my analysis in the previous section focused on that Order. Mr. Kahal, however, has based his entire examination of SSES 2 and PP&L capacity on the criteria found in Section 1323.

Q. What is your understanding of the Section 1323 requirements for the tests for physical and economic excess capacity?

A. Section 1323 of the Pennsylvania Public Utility Code states, in part:

> "For the purposes of this section, a rebuttable presumption is created that a unit or units or portion thereof shall be determined to be excess unless found to be needed to meet the utility's customer demand plus a reasonable reserve margin in the test year or the year following the test year, or if it is a baseload unit, it is also found to produce annual economic benefits which will exceed the total amount of the annual cost of the plant during the test or within a reasonable period following the test year." [emphasis added] (66 Pa. C.S. §1323)

The first underlined passage is the test the Commission has referred to as the test for "physical" excess capacity; the second underlined passage presents what has been called the test of "economic" excess capacity. (See Slip Opinion at 52; Docket No. R-860378, Order entered March 10, 1987).

B. Section 1323's Physical Excess Capacity Test

Q. Does your analysis of physical excess capacity under Section 1323 differ from your analysis of PP&L's compliance with the 1985 Order?

A. No. The standards -- and therefore, my analysis and conclusions -- are identical. My finding that SSES 2 is needed to meet PP&L's reserve needs is sufficient to overcome the rebuttable presumption of physical excess capacity set forth in the first part of Section 1323.

C. *Section 1323 and Analysis of the Economic Benefits Provided by SSES 2*

1. *Appropriate Standards for Applying the Statutory Test for Economic Excess Capacity*

Q. What is the test for economic excess capacity which you apply?

A. I am informed by counsel that there is no requirement that PP&L apply a test for economic excess capacity to SSES 2, because this is not PP&L's first claim for rate base treatment of SSES 2 and because the unit is, in fact, already included in rate base. Nonetheless, Mr. Kahal has devoted a great deal of his testimony to a discussion of Section 1323 and its economic excess test. This section of my testimony responds to Mr. Kahal's economic excess analysis.

Q. Section 1323 states that a baseload unit will be found to be excess on economic terms unless it is found "to produce annual economic benefits which will exceed the total annual cost of the plant during the test year or within a reasonable period following the test year." As a utility economist, do you find the operational meaning of this test to be self-evident?

A. No. This test requires amplification before it can be applied in an analytical sense. Specifically, application of the test requires that three corollary questions be answered: (1) In relation to what should the benefits of SSES 2 be assessed -- i.e., what is the appropriate proxy against which SSES 2 should be measured?; (2) How does one define a reasonable period of time?; and (3) How should these benefits and costs be measured?

2. *Critique of Mr. Kahal's Economic Analysis*

Q. How has Mr. Kahal applied this test?

A. Mr. Kahal has taken what is, to my knowledge, an unprecedented approach to determining the appropriate comparison for SSES 2. Rather than comparing SSES 2 against a specific baseload generation alternative available to PP&L, he has measured SSES 2's busbar costs against a series of prices from a PP&L study that he interprets as the market price of power. Even if this hypothetical series of prices is an appropriate estimate of market prices, and I have reservations concerning the reliability of the estimates, it is wholly inappropriate to use the market prices for a <u>deregulated</u> power market to determine the appropriate ratemaking treatment for a single generating unit in determining <u>regulated</u> revenue requirements.

Q. What are your specific criticisms of Mr. Kahal's methodology?

A. His approach has a number of conceptual flaws:

1. It is inappropriate to use a hypothetical calculation of market prices (even a calculation that is done correctly) in a proceeding designed to find the appropriate rate base for rate of return-based revenue requirements.
2. Mr. Kahal does not contend that power markets actually will be deregulated during the period he assesses. Indeed, his motive for truncating his analysis at ten years is his belief that sometime <u>thereafter</u> power markets may be deregulated. This demonstrates the inappropriateness of using "market" prices to value regulated power prices during the next ten years.
3. Mr. Kahal's approach implicitly deregulates <u>one</u> asset (within PP&L's entire portfolio of regulated generation, transmission and distribution assets) while leaving the rest

of PP&L under cost of service regulation. When -- if ever -- generation pricing is deregulated, <u>all</u> of PP&L's generation, indeed, all generation in Pennsylvania, presumably will be priced at market. Gains (relative to cost of service) from currently "underpriced" assets will be available to offset losses from "overpriced" assets. His approach ignores these "above market" benefits from PP&L's economically attractive assets.

4. The Pennsylvania Commission is in the very early stages of considering what changes might be appropriate in the way that utilities in the state are regulated. A major consideration in that investigation inevitably will be the treatment of what has come to be called "stranded costs." In this case, the OCA is seeking to circumvent that deliberative process and impose a "50-50 sharing" of its estimate of SSES 2 stranded costs under the guise of a Section 1323 examination. Moreover, it would impose stranded cost losses on PP&L <u>now</u>, not when the opening of a competitive market requires that stranded cost responsibility be assigned.

5. As a method of allocating stranded cost responsibility, Mr. Kahal's proposed 50-50 sharing is wholly inappropriate.

6. For a variety of reasons, the analysis that Mr. Kahal relies on is both speculative and biased as a measure of market prices in a deregulated power market.

Q. Your first two criticisms relate to the appropriateness of using market prices for valuing "economic excess capacity" under cost of service regulation. Can you further explain your criticisms?

A. Yes. For at least 50 years -- longer in some jurisdictions -- U.S. electric utility revenue requirements have been determined on a cost-of-service basis. This remains the case today, including in Pennsylvania. The principles of cost of service are well known and I will not summarize them. The key relevant element is that the ratebase for ratemaking purposes is the depreciated historical cost of assets devoted to, or "used and useful" in, the public service.

It always has been the case that only prudent investments were entitled to ratebase inclusion. "Used and useful" has been more of a moving target. As early as 1979, this Commission made a small and temporary ratebase disallowance on the grounds of excess capacity. However, as discussed above, it has been circumspect in disallowing investment recovery on excess capacity grounds, allowing reserve margins considerably higher than pool minimums. In my opinion, that policy has been entirely correct.

On previous occasions, before this Commission and elsewhere, I have testified that "economic excess capacity" is a flawed concept. This is not because I am opposed to market pricing as a full alternative to cost-of-service pricing. In my prior testimony, I have indicated that market pricing is a fully acceptable alternative to cost of service provided that (1) appropriate notice is given so that utility investors can choose (or not) to invest in assets with market-determined value; (2) utilities have ordinary commercial freedom to invest (or not), unconstrained by a requirement to serve; and (3) market pricing is applied even-handedly to all assets, not selectively and only to high-cost assets. By these standards, 1323's economic excess capacity test is bad regulatory policy. Fortunately, the Commission is given very broad latitude in interpreting and applying it. In the instant case, I am advised it need not be applied at all.

However, to the extent that the economic excess capacity test in Section 1323 is relevant, the three questions I noted at the beginning of this section must be answered. The question relevant to Mr. Kahal's use of a market test is against what alternative should the baseload unit be measured? Mr. Kahal proposes to use a PP&L study which sets forth one possible market price in a fully competitive bulk power market. However:

- The spot market was not a long-term means of meeting jurisdictional requirements available to PP&L when the SSES 2 unit was first started in the mid-1970s.
- The spot market was not a long-term alternative at the time the unit was completed and first subjected to rate inclusion review in the mid-1980s.
- The spot market is not a long-term alternative in the mid-1990s.

PP&L (and all other Pennsylvania electric utilities) remain <u>fully</u> subject to regulation today. Mr. Kahal does not propose to deregulate prices, including the price of power from SSES 2. Rather, he seeks to base a <u>regulated</u> disallowance of a return on shareholders' equity investment on a purely hypothetical and, from a regulatory perspective, wholly irrelevant spot market price.

Q. Does Mr. Kahal seek to justify his use of a market price measure for his "economic excess capacity" test?

A. Yes. He states that:

> This concept of economic excess capacity is consistent with the Commission's recent adoption of competitive bidding as a means of acquiring capacity by Pennsylvania utilities. As a practical matter,

> utilities today subject major power supply decisions to a competitive market test [OCA Statement 2, pp. 17-18].

This is his entire defense.

To focus on the first sentence, competitive bidding for new generation is an entirely inapt precedent for Mr. Kahal's proposal. The most important of several reasons is that bid prices are freely offered by generators who are allowed to bid whatever price they choose. The winning bidder receives its own bid price, not a hypothetical "market" price *determined by the Commission or utility. Indeed, avoiding dependence on such* hypothetical projections of prices is one of the main motives for moving to competitive bidding. A second notable difference is that bids in competitive auctions are, in most cases, for long-term firm purchases. No QF will bid a price that it does not believe will earn it at least its total costs, including a market return on its investment. Conversely, the hypothetical price used by Mr. Kahal is a short-run, spot energy price to which he adds a short-run, spot price for capacity. These prices are not compensatory of the full costs of any QF and would not be bid into any competitive solicitation for long-term from power.

Mr. Kahal's second sentence referring to utilities' use of competitive market tests is too vague to be addressed. Use of competition is hardly new, for example, in fuels contracting and selecting equipment vendors. The use of formal competitive procurement mechanisms to "test" power supply decisions, *in the formal sense of competition auctions,* is merely a generalization of the first sentence.

Q. Your third objection to Mr. Kahal's methodology is the selective application of the market test only to SSES 2. Why is that improper?

A. If there is a market price of power, that price applies equally to all power produced at a particular time and general location. If a market price is relevant to valuing Susquehanna, it is equally relevant to all generating units in Pennsylvania. This is how markets work. However, Mr. Kahal has not applied his methodology to PP&L's other assets, specifically the transmission and distribution assets. These assets have market values will above their historical cost. For example, application of fair market value test to PP&L's transmission and distribution assets would indicate a market value that is more than $1.3 billion above historical costs. A consistent, symmetrical application of Mr. Kahal's methodology would require a corresponding positive adjustment to the Company's current rate request to reflect those assets with market values above costs.

Applying a market test piecemeal to only PP&L's newest station, one which may not be its most economic investment when viewed with hindsight, is "lesser of cost or market" valuation. This type of asymmetric valuation is blatantly confiscatory and hence is highly improper.

Q. In your fourth and fifth criticisms, you reference the Commission's current general investigation of regulatory change and the issue of stranded costs specifically. Can you further explain?

A. Yes. It is widely accepted that a combination of circumstances has led to very large differences between embedded revenue requirements and the prices that would prevail under fully competitive circumstances. This problem is compounded by regional excess capacity in most areas of the country, a problem due in part to regulatory policies requiring purchases from QFs.

The stranded cost problem is very significant. While estimates vary, some analysts estimate the scale of potentially stranded cost at more than 100 percent of common shareholders' equity for the sector as a whole. The disposition of potentially stranded costs is the issue at the center of the debate about restructuring utility regulation. Until it is resolved, no meaningful progress toward a competitive market is possible.

The principal position is that investments that are "stranded" by a change in the rules governing utility pricing properly are recovered from the customers on whose behalf the investments were made. Important examples of this position are FERC's position in the recently issued Notice of Proposed Rulemaking, and the comments received by FERC from NARUC and in the joint statement by the noted regulatory experts Kahn, Joskow and Baumol.

However, my purpose is not to debate the issue. I merely wish to note that in recommending a 50-50 "sharing" of the supposed difference between the embedded cost of SSES 2 and its near-term market value, Mr. Kahal is short circuiting the fair and explicit consideration of the difficult issue of stranded costs. In my opinion, it would be most inappropriate to set a key precedent on stranded cost treatment in a single utility's rate case or with reference to a single facility.

Q. At page 9 of his testimony, Mr. Kahal asserts that in view of the possible advent of competition, it is important to reduce prices and the cost of uneconomic assets and that "a continuation of an equity disallowance on Susquehanna Unit 2 is consistent with that objective." Do you agree?

A. Absolutely not. Mr. Kahal appears to be saying "PP&L shareholders have been denied an equity return for the first ten years. The market may force them to fail to earn an equity return in the future. Why not deny them an equity return now, also?" Reducing prices by simply reducing profitability does nothing to better prepare the utility for a competitive market. Indeed, denying an equity return on SSES 2 will only weaken PP&L, making it less capable of successfully surviving the transition to competition.

Q. You have referred to Mr. Kahal's proposal as a 50-50 sharing. Is it not the case that he refers to his proposal as a 75-25 sharing between customers and the Company?

A. Yes, but this is a mis-characterization. The 75-25 sharing assumes that SSES 1 receives a full return on investment. However, Mr. Kahal is opposing PP&L's ECR treatment of the capacity returning to native load service. Neither Mr. Kahal, nor the OCA are committing themselves to full ratebase inclusion of SSES 1, and Mr. Kahal's position on "economic excess capacity would apply equally to SSES 1."

Q. Your sixth criticism relates to the use of PP&L's studies as a basis for forecasting market prices. Can you explain this criticism?

A. Yes. Mr. Kahal uses a PP&L study, actually two related studies, that contain a view of market prices. One study is used to provide what is essentially a forecast of marginal energy-only prices. To this, Mr. Kahal adds 0.5 cents per kWh as his estimate of capacity value. From the second, he extracts the "sustenance" price for later periods. For the earlier period (1994 to 2003), he derives a price of 2.9 to 3.9 cents per kWh. For the latter period, 2000 to 2005, he derives a price rising from 4 to "almost 5" cents by 2005. He also considers other PP&L sources that show "market" prices rising from 2.5 cents at present to 3.1 cents in 1998, and information from Mr. Sipics suggesting a 1995 market price of 2.7 cents rising to 4 cents in 2000. From this, he distills a 5-to-10-year average of 3 to 4 cents, which he concludes is reasonable. For computational purposes, he assumes 3.5 cents.

I first note that PP&L's prices do not represent predictions of the equilibrium market prices that would prevail if PJM generation were fully deregulated, since they do not reflect key aspects that would exist in a competitive generation market. For example, the PP&L data are based on a characterization of PJM generation that assumes units continue to operate as they would in a regulated world. However, in an unregulated world, "uneconomic" units probably would be shutdown, producing market prices above those developed by PP&L. I note parenthetically that in a fully deregulated market units such as SSES 2 (which has the lowest marginal operating costs among PP&L's steam units) will likely be the units to continue operating at high utilization levels.

In addition to the conceptual problems with Mr. Kahal's use of PP&L's prices, I note that his price projections for the next several years are depressed because of excess capacity on PJM. This accounts for the low value of capacity contained in the PP&L studies and presumably (although he does not say) explains the low value of capacity used by Mr. Kahal. An adder of 0.5 cents per kW, at average load factor for PJM, is about 25-30 dollars per kW year. This is insufficient to pay for even the cheapest form of capacity and is well less than half of the PJM capacity deficiency payment, which in turn is the PJM utilities' consensus view of the annual cost of a combustion turbine. Thus, in relying on these cost estimates, Mr. Kahal is using the fact of excess capacity at <u>other</u> PJM utilities to deny ratebase inclusion of PP&L capacity.

3. *Analysis of Section 1323 Economic Benefits Test*

Q. In your opinion, what is an appropriate method of assessing the benefits of SSES 2?

A. The calculation of the economic benefits of a unit must be a comparative undertaking that examines the costs PP&L would have incurred under an alternative generation arrangement. The standard methodology requires a cost modeling exercise that replaces the plant in question with a source of equivalent generation, and compares the estimated costs to ratepayers under the two system configurations.

The choice of proxy must fulfill several criteria. First, the proxy must generate the type of power (baseload, intermediate or peaking) provided by the plant in question and provide equivalent capacity. The proxy must have been a viable alternative for the utility. It must have been a feasible alternative for the utility, given the constraints posed by environmental regulations. Finally, the proxy must be consistent with the precedents that govern the analysis of a plant's economics.

Q. Given the criteria you have described, what do you believe is the appropriate proxy for assessing the economic benefits of SSES 2?

A. I believe that PP&L's least-cost feasible alternative would have been a baseload coal plant coming on line in the mid 1990s. This coal plant proxy is the appropriate alternative for Section 1323 analysis of SSES 2 because:

- SSES 2 was designed to provide baseload power, and therefore, the proxy -- i.e., the plant that PP&L would have undertaken in the absence of SSES 2 -- must also be a baseload plant.
- In 1985, coal generation was the most economic technology for providing baseload capacity. At that time, the only other possible alternative was combined-cycle gas turbine units (CCGTs). However, given expected performance of combustion turbines, the anticipated rapid increase in gas prices and the historical volatility of gas prices, CCGTs were viewed as a much less economically attractive baseload option.
- The Commission has repeatedly relied upon the use of a baseload coal plant proxy as the metric for assessing the benefits of nuclear power plants in the context of a Section 1323 economic analysis.[13/] Similarly, in the context of avoided-cost estimates the Commission itself has stated that 52 PA Code 57.34 (c) (4) (iii) requires that a coal plant proxy be used if a utility has not committed to sufficient plant to meet its forecast reserve requirement[14/] and the Pennsylvania Commonwealth Court has confirmed that a coal plant is the appropriate proxy for analyzing the costs of a baseload generating unit.[15/]

PP&L planning studies suggested that its Montour site would have been the most appropriate location for a large-scale coal plant.

13/ See, for example, Orders in Docket No. R-870732 and Docket No. R-891364.

14/ PAPUC Opinion and Order, Docket Nos. P-870235, C-913318, P-910515, C-913764.

15/ Commonwealth Court of Pennsylvania, Opinion in case No. 2788 CD 1993, p. 36. The Commonwealth Court did find that the Commission erred in requiring a coal plant proxy when intermediate power was needed.

Q. Does this coal proxy conform with previous Commission precedents addressing the form of economic benefits tests?

A. Yes. The Commission has consistently accepted a baseload coal plant proxy as the appropriate comparison for a nuclear plant. For the purposes of Section 1323 analysis, the Commission has also recognized that the hypothetical coal plant should be one whose planning and construction begin no earlier than the time of the rate case evaluating the nuclear plant's inclusion in rate base.[16/] In the instant case, that suggests that the appropriate proxy is a hypothetical coal plant whose planning and construction began after 1985. At that time, it took approximately nine years to plan, permit and construct a large-scale coal plan; thus, the plant would have come into service in the mid-1990s.

Q. The second issue you raised with respect to the application of the Section 1323 test for economic excess capacity concerns the definition of the "reasonable period of time." How do you address this aspect of the standard?

A. As noted by Mr. Kahal, this is clearly a matter of judgment; his analysis focuses on the next five to ten years.[17/] His approach is broadly within the time frame previously used by the Commission,[18/] and I adopt it here; my analysis examines the ten-year period beginning with the future test year.

16/ See, for example, Orders in Docket No. R-870732 and Docket No. R-891364.

17/ Direct Testimony of Matthew I. Kahal, p.18.

18/ See, for example, Orders in Docket No. R-870732 and Docket No. R-891364.

Q. The third issue you raised regarding the economic excess capacity test concerned the way in which benefits and costs would be measured. How have you measured the cost of SSES 2 relative to its alternative?

A. The statute specifically calls for a comparison of annual benefits to annual costs. This implies that studies of cumulative life-cycle costs or benefits would not be probative under the statute, which is consistent with prior Commission findings.[19] To comply with the statute, I have compared annual revenue requirements for SSES 2 to the annual revenue requirements for the hypothetical alternative in each year from 1995 through 2004.

4. *Design of the Net Economic Benefits Test for SSES 2*

Q. Please describe the specific analyses you conducted to determine whether PP&L's investment in SSES 2 meets the annual net economic benefit test described in Section 1323 of the Code.

A. In brief, I structured the analysis to measure PP&L's system-wide future costs of operating with SSES 2 relative to its system-wide future costs of operating with another baseload supply alternative that provided essentially identical generating and capacity benefits to the system. However, this analysis requires only a comparison between the incremental differences in PP&L's future revenue requirements arising from the substitute coal-fired plant relative to retaining SSES 2. This incremental methodology is the standard one used in economic benefits analysis and has frequently been used by Mr. Kahal.[20]

19/ See Opinion and Order, Docket No. R-870732 at 57 and Docket No. R-891364 at 254-256.

20/ Public Service Commission of Maryland, In the Matter of the Application of Baltimore Gas and Electric Company for Review and Approval of the Power Sales and Purchase Agreement with ANS Northside, Inc., Case No. 8473, Direct Testimony of Matthew I. Kahal, November 1992, pp.13-14; "An Economic and Need for Power Evaluation of Baltimore Gas and Electric Company's (continued...)

Q. What options did you select for your analysis?

A. I selected two scenarios for detailed analysis, which differ in the way they incorporate 990MW of capacity in PP&L's system.

- The Base Case: In this scenario, SSES 2 provides 990MW of nuclear capacity to PP&L as of January 1995, with jurisdictional base rate treatment as indicated in the company's current filing -- which will result in complete recovery of all costs and capital returns, from that date forward.
- The Alternative Case: SSES 2 is nonexistent in this scenario; it is replaced by two new coal-fired units completed in the mid 1990s. The coal units also provide a combined capacity of 990MW to PP&L.

The alternative case assumes that all contract sales continue at levels assumed in the base case, resulting in the same total jurisdictional capacity in both cases. It also recognizes that the addition of 990MW of capacity at Montour would have required construction of additional transmission and switchgear facilities.

The models are identical in all other respects, including the configuration and operating characteristics of the rest of PP&L's facilities and the schedule of planned power sales.

Q. What are the main assumptions used in your base case analysis?

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[20] (...continued)
Perryman Plant," May 1991, pp.IV-5-9. In these analyses, Mr. Kahal calculated annual figures ,and then derived their cumulative present value; in the context of Section 1323 analysis, examination of the annual estimates is sufficient.

A. My analysis uses data relied upon by, or prepared for me by, PP&L personnel. The base case incorporates the capital structure, debt and equity returns, and depreciation schedules that PP&L has put forth in its filing in this case. It includes capital and operating costs associated with SSES 2 and its associated common plant. PP&L's nuclear and planning departments have provided me with information on operating costs, and the Company's tax personnel have provided information on the calculation of federal, state and other taxes. Major assumptions are summarized in Exhibit WHH-2.

Q. What are the main assumptions used in your alternative analysis?

A. I have relied upon the 1993 Technology Assessment Guide (TAG) developed by the Electric Power Research Institute (EPRI) for cost and operating data for the coal plant. The TAG is an industry standard that is often used as a source for operating and cost assumptions for these types of analyses.[21/] In consultation with PP&L system planners, I determined that the costs included in the EPRI TAG would be conservative estimates of PP&L's costs to build an equivalent plant. As built, the plant meets all environmental requirements for the area. Because PP&L would have located the plant at the Montour facility, the coal plant's fuel costs are based on the Company's forecasts for its Montour plant. Major assumptions are summarized in Exhibit WHH-3.

Q. What are the outputs of your revenue requirements analysis?

21/ Mr. Kahal has previously used the EPRI TAG as a standard for determining the reasonableness of plant cost estimates; see "An Economic and Need for Power Evaluation of Baltimore Gas and Electric Company's Perryman Plant," May 1991, p.III-19.

A. For SSES 2 and the coal plant, revenue requirements consist of the capital charges of the unit and associated operating costs. Since the dispatch of other PP&L units changes with the inclusion of the coal plant, the operating costs for the other PP&L units also change. I adjust the revenue requirements of the coal plant to account for corresponding changes in operating costs.

The difference between the total revenue requirements for SSES 2 and the total revenue requirements for the coal units provides an indication of the relative economic benefits of SSES 2. This calculation shows, by year, whether the existence of SSES 2 yields lower total revenue requirements to PP&L's ratepayers.

5. *Economic Benefits of SSES 2*

Q. What are the results of your analysis?

A. I find that SSES 2 provides annual net economic benefits to PP&L ratepayers in the test year and in virtually all years thereafter. Exhibit WHH-4 summarizes my findings. Under the most conservative assumptions, I find that PP&L rates are $4 million to $93 million lower per year with SSES 2 than with the alternative coal plant; under these assumptions, the only exceptions are in 1997 and 1998, when SSES 2 yields slightly higher revenue requirements than does the coal plant. In sensitivity analyses that rely upon more realistic data, SSES 2 provides lower revenue requirements in every year in the study period.

Q. What are the sensitivity analyses to which you refer?

A. I have examined the common-plant assumption and the impact of the modified sinking fund (MSF) depreciation that the Company implemented to protect its customers from rate shock in the early and mid 1980s.

The base case analysis assumes that 50 percent of all capital additions to common plant made in 1989 and thereafter are attributable to SSES 2.[22/] This is a very conservative assumption; a study commissioned by PP&L indicated that only 27 percent of original common plant costs were attributable to SSES 2, with the remaining 73 percent of costs necessary for the operation of SSES 1.[23/] I believe it is reasonable to assume this figure would also apply to capital additions to SSES common plant. Applying the 27 percent ratio to original plant and capital additions for SSES common plant results in SSES 2 providing annual net benefits of $20 to $121 million.

The second sensitivity analysis examines the impact of alternative book depreciation arrangements. The MSF depreciation method as applied to SSES 2 resulted in a pattern of depreciation for the years 1985-1993 that was well below the level that would have prevailed if the plant had been depreciated on a straight-line basis throughout its life. Correspondingly, the MSF method results in annual depreciation on SSES 2 in the 1994-1998 period that is well above straight-line levels. My base case analysis incorporates the remaining high depreciation charges for 1995-1998 as proposed by PP&L in the current filing. In a sensitivity analysis I have calculated the net economic benefits of SSES 2 as if it had been depreciated on a straight-line basis, and find that had the unit (and its common plant) been depreciated on a straight-line basis, the net economic benefits of SSES 2 during the 1995-98 period relative to the coal plant would have been approximately $50 to $60 million higher than my base case results indicate.

22/ For years prior to 1989, PP&L has provided breakouts of the original value of common plant attributable to SSES 2 and for the value of common-plant capital additions attributable to SSES 2. These breakouts are conservative because they were done for accounting purposes, and make no attempt to estimate the amount of common plant that was truly <u>incremental</u> to SSES 2 in an engineering and economic sense.

23/ Pennsylvania Power & Light Company, FERC Docket No. FA84-12-001, Settlement Agreement, Attachment B.

Q. What do your results suggest?

A. These findings strongly support the conclusion that if the Section 1323 economic benefits test were, in fact, relevant to the Commission's deliberations in this proceeding, SSES 2 would unequivocally pass the threshold required for a finding of annual net economic benefits within a reasonable time period. The plant consistently provides annual net economic benefits to PP&L's customers.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit WHH-1

CALCULATION OF PP&L RESERVE MARGINS
(MWs)

		94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04
[a]	Winter peak load	6,605	6,725	6,790	6,915	7,050	7,185	7,330	7,465	7,600	7,745
[b]	PP&L owned/leased capacity	8,543	8,540	8,540	8,588	8,588	8,570	8,552	8,552	8,552	8,552
	Firm capacity sales										
[c]	AE	129	129	129	129	129	129				
[d]	BG&E	129	132	132	132	132	132	132			
[e]	JCP&L	945	945	756	567	378	189				
[f]	Interruptible load adjustment	345	345	345	345	345	345	345	345	345	345
[g]	Capacity Credits	587	183	0	0	0	0	0	0	0	0
[h]	PP&L capacity resources	7,098	7,496	7,868	8,105	8,294	8,465	8,765	8,897	8,897	8,897
[i]	Capacity over peak	493	771	1,078	1,190	1,244	1,280	1,435	1,432	1,297	1,152
[j]	% reserve margin	7.5%	11.5%	15.9%	17.2%	17.6%	17.8%	19.6%	19.2%	17.1%	14.9%

Sources:
[a]-[g] Exhibit JFS-1
[h] [b]-[c]-[d]-[e]+[f]-[g]
[i] [h]-[a]
[j] [i]/[a]

Exhibit WHH−2

MAJOR DATA INPUTS AND SOURCES FOR SSES 2 REVENUE REQUIREMENTS ANALYSIS

	SSES 2	SSES 2 Common	Source
Original Plant , 1985 [1]	1,011,847,291	333,172,169	PP&L
AFUDC, 1985 [1]	408,984,906	116,192,567	PP&L

Book Depreciation Schedule: Modified Sinking Fund (through Q3 1995)
Levelized MSF (Q4 1995 − 1998)
Straight Line (1999−2004)

	PP&L	
Rates of Return		
Debt	7.97%	Current Filing, Testimony of Paul Moul
Preferred Equity	7.31%	Current Filing, Testimony of Paul Moul
Common Equity	13.00%	Current Filing, Testimony of Paul Moul
Capitalization Ratios		
Debt	46.53%	Current Filing, Testimony of Paul Moul
Preferred Equity	7.59%	Current Filing, Testimony of Paul Moul
Common Equity	45.88%	Current Filing, Testimony of Paul Moul
Combined Federal and State Income Taxes		
1995	42.14%	PP&L 1994 Annual Report: (Fed. + State) − (Fed. * State)
1996	41.99%	PP&L 1994 Annual Report: (Fed. + State) − (Fed. * State)
1997 +	41.49%	PP&L 1994 Annual Report: (Fed. + State) − (Fed. * State)

	Capacity Factor (%)	SSES 2 Capital Additions	SSES 2 AFUDC
1995	77	22,341,000	2,409,000
1996	91	19,653,000	2,847,000
1997	77	18,860,500	2,539,500
1998	77	19,271,500	978,500
1999	91	17,760,500	239,500
2000	77	13,398,500	101,500
2001	77	13,398,500	101,500
2002	91	13,398,500	101,500
2003	77	13,398,500	101,500
2004	77	13,398,500	101,500

Sources:
Capacity factors: PP&L
Capital additions and AFUDC: PP&L

[1] The model is based on original cost, adjusted for historical depreciation and taxes.

Exhibit WHH–3

MAJOR DATA INPUTS AND SOURCES FOR ALTERNATIVE COAL PLANT REVENUE REQUIREMENTS ANALYSIS

	Coal Plant	Source
Original Capital Cost	1,197,116,963	EPRI, Technical Assessment Guide, Electricity Supply – 1993
Original Capital Cost, Switchgear	18,000,000	Provided by PP&L
AFUDC, Coal Plant and Switchgear	264,697,211	EPRI, Technical Assessment Guide, Electricity Supply – 1993
CCPI, Coal Plant and Switchgear	274,677,324	EPRI, Technical Assessment Guide, Electricity Supply – 1993
Book Depreciation Schedule	Straight Line, 30 years	EPRI, Technical Assessment Guide, Electricity Supply – 1993
Capital Additions, per Year	0	(Per EPRI)
Capacity Factor (%)		EPRI, Technical Assessment Guide, Electricity Supply – 1993
1995	87	
1996	76	
1997	79	
1998	79	
1999	79	
2000	81	
2001	82	
2002	83	
2003	83	
2004	84	
Rates of Return, Capitalization Ratios, and Income Taxes	See Exhibit WHH–C	

Exhibit WHH-4

NET BENEFITS TO PP&L RATEPAYERS FROM SSES 2

SSES 2 Advantage / (Disadvantage)

($ Millions)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Base Case vs. Alternative Coal Plant	3.801	20.496	(14.809)	(0.046)	86.714	42.638	53.811	93.381	38.805	48.891
Sensitivity #1: Incremental SSES Common Costs	37.357	55.852	19.889	34.144	114.685	70.385	82.542	121.189	65.722	74.913
Sensitivity #2: Straight Line Depreciation for SSES 2 and Common Plant	50.970	81.270	42.189	53.411	82.768	38.710	49.728	89.422	34.968	45.177

Note: Base Case assumes levelized depreciation of remaining MSF depreciation for Q4 1995-1998 and straight-line depreciation thereafter. It also assumes that for common capital and fixed costs for which no unit-specific breakout is available, 50 percent of common cost and fixed O & M costs are attributable to SSES 2. Sensitivity #1 assumes that 27 percent of capital related costs are attributable to SSES 2. Sensitivity #2 assumes a straight-line depreciation schedule over the entire life of the plant.

Epstein St. 1
R-943271
5/26/95
HBC
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	
	:	Docket No. R-00943271, R-00943271C001
V.	:	
	:	
PENNSYLVANIA POWER & LIGHT COMPANY	:	et seq.

SURREBUTTAL RESPONSE TO PP&L WITNESS GEORGE T. JONES
(STATEMENT 15-R)

Mr. Gorge T. Jones', Vice President Nuclear-Engineering, Pennsylvania Power and Light Company (PP&L), rebuttal testimony regarding nuclear power operations, nuclear waste disposal and problems with Thermo Lag and spent fuel storage at the Susquehanna Steam Electric Station (SESS) was general, vague, arbitrary and based on unreliable criteria.

Mr. Jones termed criticisms of Susquehanna's operating record as "grossly unfair and in many cases simply wrong." (Page 2, Lines 17-18.) Mr. Jones arbitrarily selected data to substantiate his claim, specifically the Nuclear Regulatory Commission's (NRC) Systematic Assessment Licensee Performance (SALP) and the plant's operating capacity. Unfortunately, these are flawed indices with which to assess a plant's longevity and operating and safety record.

The SALP process rates licensee performance in four functional areas: Plant Operations, Maintenance, Engineering and Plant Support (radiological controls, security, emergency preparedness, fire protection, chemistry and housekeeping). Mr. Jones' description of the SALP process as a tool used "to determine the level of management attention it must devote to a licensee" (Page 3, Lines 7-8.) is disingenuous and misleading. Unless a plant has a major accident (Three Mile Island) or shutdown by NRC decree (Peach Bottom) staffing levels remain relatively steady throughout the industry.

Moreover, the SALP evaluation system is limited and restrictive with the following grading scheme: 1 = above average; 2 = average; 3 = below average. The NRC can also indicate "improving" or "declining" trends. The charge of the NRC is to allow the industry to monitor itself with minimal regulatory interference. Nuclear power operators give more stock to evaluations conducted by the Institute for Nuclear Power Operations (INPO.) For example, an INPO inspection "pointed out some areas for improvement at the plant, and were taking appropriate action." (Shareholders Newsletter," (July 1, 1993.) Unfortunately, this data is proprietary and rarely released to the public.

Even if one accepts the SALP report as an indicator of a plant's performance, this tool has been proven to be unreliable. For example, *prior* to the security breach at Three Mile Island (TMI) on February 7, 1993, the SALP evaluation grade for plant security was a "1." *After* the intrusion, TMI's plant operator, GPU Nuclear (GPUN), received a "1" in Plant Support which includes security. In fact the NRC's Incident Investigations Team's (ITT) concluded: "The ITT reviewed reports for NRC inspections conducted during the last three SALP periods and found no significant indications of precursors. The SALP evaluation process also revealed no significant indications or precursors." ("NRC Reviews," NUREG-1485, Section 4.2.2.) Clearly, the veracity of SALP evaluations is negligible.

Capacity factor is a misleading yardstick frequently utilized by the nuclear industry. Susquehanna's average capacity factor of 78.4% is virtually meaningless as a barometer for plant longevity, safety or economic vitality. For example, at the end of 1991, Yankee Rowe's operating capacity factor was 74.11%. (Nuclear Regulatory Commission.) Yankee Atomic, Yankee Rowe's operator, closed the plant prematurely on February 26, 1992 due to the cost to comply with NRC regulations and the embrittlement of the reactor vessel. Through November 30, 1992, San Onofre-1's annual capacity factor was 83.66%. (Nuclear Regulatory Commission.) Southern California Edison closed the plant the following month for economic reasons.

Mr. Jones stated, "Most of the violations, particularly in later years of operation, have been Severity Level IV or V, the lowest categories." This is obviously an admission that in the "earlier years" most of the violations were of a more serious nature, i.e. Severity Level I through III. Severity Level IV and V violations are indeed more common throughout the industry; however, they identify problems and weaknesses at a nuclear power plant. In other words, a Level I violation is analogous to a felony while a Level V violation is similar to a misdemeanor.

Neither the SALP or capacity factor rating address generic problems at nuclear power plants. For instance, core shroud cracking, reactor embrittlement, vulnerable containment structures and faulty water level indicators have been identified as generic challenges at Boiling Water Reactors. The process employed by the NRC to investigate these issues is highly suspect. The NRC was harshly criticized by a 19 year veteran of the nuclear industry who was under contract with the Commission. John Darby, a top industry engineer, reviewed Individual Plant Examination (IPE) submittals which are designed to examine and determine the possibility of serious accidents at nuclear power plants. In a memo to the NRC on March 17, 1995, Mr. Darby stated:

> Also, I have been told in no uncertain terms to 'don't look so hard and don't ask so much.' The NRC spends more time haggling over the questions to ask and the precise wording of the questions than I spend doing my entire review of the IPE submittal. I am continually re-wording and re-writing questions to meet some undefined goal of what is 'acceptable' to ask the licensee.

Clearly, the NRC is not an aggressive evaluator of design based challenges or site-specific problems that arise at the Susquehanna nuclear power plant or elsewhere.

Internal reporting, Licensee Event Reports (LER), of plant problems has recently increased at the SESS. This measure of a plant's operating performance was omitted from Mr. Jones rebuttal testimony. The number of LER's at Unit-1 in 1991 was 25 and 15 were reported at Unit 2. (Nuclear Regulatory Commission, LER's through December 31, 1991.) By 1992, PP&L reported a decline: 18 LER's at Unit 1 and 14 at Unit 2 (Nuclear Regulatory Commission, LER's through December 31, 1992.) The following year another decrease was noted: 11 LER's at Unit 1 and 10 at Unit 2. (Nuclear Regulatory Commission, LER's through December 31, 1993.) However, in 1994 the number of Licensee Event Reports increased by 30 % to 19 at Unit 1 and 9 at Unit 2, precisely at a time where Mr. Jones boasted of a decline in the severity level of NRC violations. (Nuclear Regulatory Commission, LER's through December 31, 1994.)

The number and frequency of problems at the SESS has remained consistent. PP&L has simply chosen to be more forthright in reporting incidents to the NRC as a means of mitigating and deflecting harsher severity levels in Notice of Violations (NOV.)

Mr. Jones also did not disclose that PP&L tested Thermo Lag in 1981 *prior* to its installation at Susquehanna. Under standard testing criteria, Thermo Lag failed the tests. This problem was not discovered by the NRC's Office of Inspector General until 1992 and was not made public until April 1995 when a response to a Freedom of Information Act request was published. The NRC did not cite PP&L for the Thermo Lag violation and refused to issue fines for other fire protection violations. Susquehanna continues to use the faulty fire retardant and Rubin Feldman, president of Thermal Sciences Inc., the manufacturer of Thermo Lag is scheduled to go on trial this month on seven criminal counts relating to falsifying Thermo Lag testing records.

Mr. Jones asserted: "Finally the company has dealt thoroughly with the concerns raised about the adequacy of spent fuel pool cooling. Both PP&L and the NRC have concluded that this issue does not raise any significant safety concerns." (Page 4, Lines 12-14.) Mr. Jones failed to note that those concerns were initially raised by Donald Prevatte and David Lochbaum, formerly consulting engineers at Susquehanna. Conrad McCracken, chief of the NRC's plant systems branch identified it as an issue that needs to be "addressed" and the NRC sent a notice to all Boiling Water Reactor owners concerning this problem. PP&L changed procedures, trained personnel and replaced some equipment in response to these concerns. The two engineers made a formal presentation to the NRC on October 1, 1993. Mr. Jones neglected to mention the Commonwealth of Massachusetts found similar spent fuel cooling problems at the Pilgrim nuclear power plant and Washington Nuclear Power Reactor Number 2 (Hanford) also identified a similar problem.

Mr. Jones flippantly dismissed the radioactive waste problem at SESS: "Likewise, disposal of radwaste is being addressed on a statewide basis and national level. The wastes being generated today at the plant are being handled on site, in full compliance with NRC all regulations, and present no threat to the health and safety of the public." (Page 4, Lines 8-12.) And in response to Data Request to the Office of Consumer Advocate Mr. Jones stated PP&L contributed funding to "statewide screening, licensing activities, technical studies and public outreach necessary for the siting of the facility." However, Mr. Jones failed to provide information relating to the current problems of siting a low-level radioactive waste facility in Pennsylvania. According to the "Appalachian Compact Users of Radioactive Isotopes" (ACURI) newsletter, of which PP&L is represented on the Board of Directors (Roger A. Stigers, H.P.), project delays and cost overruns prompted the Pennsylvania General Assembly to pass a "resolution directing the Legislative Budget and Finance Committee to conduct an immediate audit of payments by the state's Department of Environmental Resources to its contractor, Chem-Nuclear Systems Inc., for activities related to development of a low-level radioactive waste (LLRW) disposal facility." (March 1995, p.6.) The project will require an additional financial infusion of $26 to $90 million. This development further delays siting, screening, technical studies and "public outreach" of a LLRW site. Therefore, the SESS will serve as a *de facto* low-level radioactive waste site even though the facility was not licensed, constructed or designed to house radioactive waste indefinitely.

Mary Wells of GPU Nuclear recently admitted in an interview with the Lancaster New Era, (Thursday, May 4, 1995, A-8), the nuclear industry is double-billing its customers for high-level radioactive waste storage. PP&L also bills its customers twice: 1) Maintaining on-site, spent fuel pools, and 2) Contributions to the Nuclear Waste Trust Fund.

Finally, Mr. Jones failed to mention PP&L's plan to move from spent fuel cooling to dry-cask storage is highly problematic and experimental. Mr. Jones admitted in his response to a Data Request (March 21, 1995) that spent fuel storage capacity is sufficient through 1997. However, PP&L's reliance on dry-cask storage is disturbing in light of the technical problems and legal delays experienced at the Palisades, Prairie Island and Oyster Creek nuclear power plants.

Respectfully submitted,

Eric J. Epstein
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DATE: May 13, 1995

OCA STATEMENT NO. 2A
R-943271
5/26/95

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00943271

SURREBUTTAL TESTIMONY

OF

MATTHEW I. KAHAL

CONCERNING
CAPACITY ISSUES

THIS TESTIMONY DELETES INFORMATION
ALLEGED TO BE PROPRIETARY

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 1995

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00943271

THE SURREBUTTAL TESTIMONY

OF

MATTHEW I. KAHAL

CONCERNING
CAPACITY ISSUES

I. <u>OVERVIEW</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. My business address is 12510 Prosperity Drive, Silver Spring, Maryland 20904. I am a Senior Economist and Principal at Exeter Associates, Inc., a consulting firm specializing in public utility regulation and energy studies. I have held that position since January 1981.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes, I have. In early April 1995, I submitted direct testimony on behalf of the Office of Consumer Advocate (OCA) on the subject of fair rate of return to be applied to the Pennsylvania jurisdictional rate base of Pennsylvania Power & Light Company (PP&L). That testimony also addressed the expected earnings on nuclear decommissioning trust funds. At the same time I submitted separate testimony concerning the generation capacity issues in this case. (OCA Statement No. 2) A statement of my qualifications and listing of past testimony accompanied my direct testimony (OCA Statement No. 1) filed in April.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. My surrebuttal testimony responds to the rebuttal testimony of PP&L witnesses Sipics, Jones and Hieronymus concerning excess capacity and witness Kleha concerning PP&L's proposal to flow non-energy capacity costs related to expiring off-system sales contracts through the ECR. I have responded separately to the PP&L rebuttal testimony on rate of return in OCA Statement No. 1A and to PP&L witnesses Berish, Chappelear and Moul on other financial issues in OCA Statement 1B.

Q. WHAT POSITION DOES PP&L TAKE CONCERNING THE ISSUE OF EXCESS CAPACITY IN REBUTTAL TESTIMONY?

A. Staff witness Metro and I have recommended disallowances for excess generating capacity in this case. The Staff disallowance is based solely on physical excess capacity, while my finding is based on <u>both</u> physical and economic excess capacity following Section 1323 of the Public Utility Code.

PP&L witness Sipics, and Dr. Hieronymus, PP&L's outside consultant, dispute both the factual finding of excess capacity and the appropriateness of a rate disallowance for excess capacity in this case. Their objections are very extensive and detailed, and I find it useful to organize their points into the following categories.

(1) <u>Reliability Concerns</u>. As a result of a variety of reliability concerns, Mr. Sipics argues that a proper reserve margin for PP&L is higher than either the Staff or OCA figures.

(2) Ratemaking Reserve Margin. PP&L witnesses argue that the reasonable range for excess capacity ratemaking should be much higher than the reserve margin target developed for reliability purposes. In particular, Dr. Hieronymus emphasizes the concept of capacity planning "lumpiness," the fact that generating capacity resources are added in discrete sizes.

(3) Net Capacity Resources and Loads. No significant factual disagreement exists concerning the magnitude of PP&L capacity resources and loads.[1] However, there are policy disagreements over whether QF capacity should be counted as part of PP&L capacity. Dr. Hieronymus also questions the recognition of interruptible load as a capacity resource and the exclusion of capacity credit sales. These are largely policy or fairness arguments.

(4) Economic Excess Capacity. Dr. Hieronymus argues that Susquehanna Unit 2 is not economic excess capacity, i.e., it passes the cost-effectiveness test over a prospective five- to ten-year time frame. He attempts to demonstrate this by comparing the revenue requirements estimates of Susquehanna Unit 2 with those for a newly constructed coal-fired plant of comparable size.

(5) Efficiency Incentives. Dr. Hieronymus argues generically against the imposition of an excess capacity disallowance on the grounds that doing so only serves to disturb utility efficiency incentives.

[1] As I indicated in my direct testimony, updated information for the winter of 1994/1995 indicates that PP&L peak demand estimates are overstated by about 25 mW.

(6) Fairness Considerations. Dr. Hieronymus argues that a disallowance for excess capacity as a general policy matter is inherently unfair, quite apart from the factual basis for such an adjustment. He believes such a disallowance is inconsistent with the concept of a "regulatory compact" and is poor public policy, absent an explicit finding of imprudence.

PP&L witnesses also heavily criticize my use of market prices as a means of addressing economic excess capacity. In addition to expressing concerns over the accuracy of market price estimates, they argue that my use of market prices for this purpose is both unprecedented (in Pennsylvania) and unfair. They argue that the OCA is selectively imposing market pricing on PP&L and seeking a particular resolution of the stranded investment issue. As I shall explain, this is a mischaracterization of the OCA's and my positions in this case.

Q. WHAT IS THE PURPOSE OF MR. JONES' REBUTTAL TESTIMONY?

A. Mr. Jones is PP&L's nuclear operations expert and his rebuttal testimony is intended to provide PP&L's perspective on its Strategy 2000 report, a document which I referenced in my direct testimony. That report is a task force study which evaluates the economic viability of Susquehanna under a phased deregulation scenario, and it outlines the cost control steps that PP&L should take to enhance that plant's cost effectiveness. Mr. Jones downplays the significance of that report and the feasibility of achieving the large cost reductions identified in the report.

Q. WHAT POINTS DOES MR. KLEHA MAKE ON REBUTTAL CONCERNING THE ECR FLOW-THROUGH OF CAPACITY COSTS?

A. PP&L's proposal in this case to flow the non-energy costs of returning capacity from expiring off-system sales contracts through the ECR was criticized by me and other witnesses (i.e., Mr. Baron and Mr. Prisco) as improper. Mr. Kleha argues that the proposed mechanism is both necessary to avoid rate cases and even-handed because PP&L would also flow through the revenues from off-system sales related to that returning capacity. He asserts that the costs to be flowed through meet the "known and measurable" test and will not lead to an overearnings problem.

Mr. Kleha also recognizes that this proposal is novel and might not be approved by this Commission. If PP&L is denied ECR recovery of these capacity costs, he argues that PP&L should be permitted to retain the energy savings provided by the returning capacity as below the line income. He estimates such energy savings to be about $15 million in 1996, but these energy savings potentially may increase dramatically in later years as more capacity returns.

Q. WHAT GENERAL OBSERVATIONS CAN YOU OFFER ON PP&L'S EXCESS CAPACITY REBUTTAL TESTIMONY?

A. With respect to the excess capacity issues, I have several very general observations to make. First, notwithstanding PP&L's extensive rebuttal testimony, there is really little disagreement over the basic facts. For example, no one disputes the load forecasts, actual reserve margin calculations, etc. Rather, the disagreements are principally policy judgments. For example, should NUG capacity be included? Even on the issue of economic excess capacity, despite Dr. Hieronymus' coal proxy presentation, there is much less <u>factual</u> disagreement than meets the eye. All relevant PP&L planning and/or market data would clearly demonstrate that the replacement power cost (over the next five to ten years) is much less than the full revenue requirements cost of Susquehanna Unit 2. Again, I can find nothing in the rebuttal testimony which challenges my Susquehanna cost estimates. My differences with PP&L are primarily policy, not factual.

The second theme in the PP&L rebuttal testimony is the tendency of Company witnesses to distance themselves from the technical reports and studies prepared by PP&L outside of this rate case. The position of PP&L witnesses on reserve margin planning is inconsistent with the Company's 1995 <u>Annual Resource Plan Report</u> (ARPR) filed with this Commission on May 1, 1995. That report also makes it very clear that a new coal plant would not be a cost-effective resource addition for PP&L at this time (or during the planning horizon). Mr. Sipics attempts to distance himself from PP&L's own analysis of market prices, while Mr. Jones does the same for the <u>Strategy 2000</u> report. PP&L engages in this "distancing" because the Company's own technical analysis does not support its position on physical <u>and</u> economic excess capacity.

The third theme in PP&L's presentation on this issue concerns a policy confusion over the purpose and nature of an excess capacity disallowance. Dr. Hieronymus does attempt to explain the difference between the "used and useful" and "imprudence" concepts in ratemaking. Nonetheless, PP&L witnesses are convinced that the prudence standard -- not the "used and useful" standard -- should control. There is a strong tendency for PP&L rebuttal arguments over excess capacity to degenerate into prudence arguments, blurring together and confusing these two perspectives.

While I agree with Dr. Hieronymus that the Commission (as well as witnesses) should exercise analytic judgment, the application of the excess capacity standard (physical and economic) first requires a <u>factual</u> determination. Once the threshold factual finding is made that excess capacity is present, the Commission then exercises its policy judgment on the appropriate ratemaking remedy -- i.e., determining what kind of excess capacity disallowance provides the proper balancing of interests and allocation of risks between ratepayers and shareholders. Dr. Hieronymus flatly opposes any excess capacity disallowance -- absent a showing of imprudence -- regardless of the excess capacity facts. In fact, he feels so strongly about this, he succeeds in defining away the problem. Based on his approach to this problem in his rebuttal testimony in this case, it is difficult to see how he could even perceive excess capacity as being present, unless imprudence was demonstrated.

Fourth, I cannot agree that an excess capacity adjustment violates the regulatory compact and is inherently confiscatory, as asserted by PP&L. This Commission has implemented excess capacity disallowances for both Susquehanna Unit 1 and Unit 2 (using differing disallowance remedies) in the mid-1980s -- ten years ago. During that ten-year time period, the Company has prospered achieving profit levels well above the industry average, achieving a single A bond rating, and unlike most utilities, raising its dividend every year. I am not suggesting that the utility's overall financial success is the proper test of each discrete ratemaking adjustment. However, the Susquehanna plant dominated the asset base of PP&L during those years, and examining the totality of PP&L's business performance is clearly meaningful.

This Commission's excess capacity policy stance has been present (albeit with changes over time) for nearly two decades. PP&L has operated absent a Commission-authorized equity return on Susquehanna Unit 2 for the last ten years. Investors in PP&L debt and equity securities clearly understand the Commission's policy on excess capacity (and other issues) and hold those securities understanding Commission policy. The excess capacity policy does not violate the regulatory compact -- it is part of it. My recommendation in this case is merely a continuation (at a much reduced dollar level) of the equity return disallowance which has been in effect for the last decade.

Q. BY EMPLOYING MARKET PRICING AND DISCUSSING THE COMPETITIVE GENERATION MARKET, ARE YOU INTRODUCING A NEW STANDARD FOR ECONOMIC EXCESS CAPACITY?

A. No. I would like to make it clear that I am in no way suggesting that market prices be substituted for cost of service pricing in this case. Doing so would mean a revenue disallowance many times larger than my $62 million excess capacity adjustment. Instead, I have used market price estimates as a costing benchmark to make the threshold determination as to whether Susquehanna Unit 2 provides economic benefits in excess of its revenue requirement cost within a reasonable period of time. In other words, market prices are merely a convenient analytical tool for implementing the economic excess capacity test. The revenue disallowance itself is based on precisely the same methodology and calculation as employed by the Commission in its 1985 rate order.

The possibility of retail deregulation in some form and at some future time justifies focusing most of our attention on Susquehanna's economic attributes during the next five to ten years. However, my excess capacity finding in no way depends on retail deregulation occurring, nor am I predicting it will happen in Pennsylvania.

Q. IN ADDITION TO THESE GENERAL OBSERVATIONS, WHAT ARE YOUR SPECIFIC FINDINGS ON EXCESS CAPACITY IN YOUR SURREBUTTAL TESTIMONY?

A. PP&L's 1995 ARPR became available approximately two weeks ago. That report demonstrates that under the Company's base forecast and preferred plan, no new generating capacity is needed to meet the Company's reliability standard until 2007 -- 12 years from now. That report also makes it clear that the target planning reserve margin, which is intended to meet PP&L's reliability standard, is approximately 12 percent.

Mr. Sipics identifies a number of potential factors which impinge on reliability. I do not dispute the existence of these factors. However, these concerns are already taken into account by PP&L and PJM in establishing the approximate 12 percent standard. They are not factors which justify going <u>beyond</u> 12 percent for reliability planning purposes.

Dr. Hieronymus argues that a ratemaking reserve margin should be greater than the planning reserve margin due to lumpiness. Where I specifically disagree with Dr. Hieronymus is that the size of the "lump" is at least equal to Susquehanna Unit 2 -- i.e., 1,000 MW. According to this view, physical excess capacity should be disregarded unless it exceeds the 12 percent planning figure <u>plus</u> 1,000 MW. Not only is this position unreasonable on its face, it further loses relevance when one realizes that Susquehanna Unit 2 was installed a decade ago.

The pivotal issue in measuring physical excess capacity concerns the inclusion or exclusion of 500 MW of NUG capacity. Irrespective of a legal mandate, Section 1323(c) provides this Commission with useful guidance on this issue. I interpret that section to mean that it is reasonable for a utility to have an opportunity to adapt and adjust its capacity resource base before recognizing QF capacity for excess capacity measurement purposes. In this context, eight years provides a fair and reasonable adjustment period. PP&L urges that this statute be ignored completely.

Dr. Hieronymus' coal proxy test makes no sense as any kind of legitimate test of the <u>prospective</u> economic net benefits to ratepayers from Susquehanna Unit 2. According to the 1995 <u>ARPR</u>, a new coal plant is demonstrably uneconomic relative to PP&L's preferred resource plan. Thus, Dr. Hieronymus' economic excess capacity analysis is merely an exercise in comparing one uneconomic resource with another resource which (if built) would be even less economic. Such a test cannot begin to address the Commission's standard of net economic benefits.

Q. WHAT IS YOUR RESPONSE TO MR. KLEHA'S ARGUMENTS IN SUPPORT OF THE ECR RECOVERY OF NON-ENERGY GENERATION COSTS?

A. I do not believe his response adequately addresses my criticisms and those of the other witnesses. Automatic recovery of non-energy generation costs through an ECR mechanism is improper ratemaking; it creates a danger of overearning; and it introduces perverse incentives to inadequately market surplus capacity.

The other aspect of Mr. Kleha's rebuttal on this issue is PP&L's request to retain fuel savings as below the line income if its ECR proposal is not adopted. I also believe that this proposal should not be approved at this time because it would authorize PP&L to charge customers for energy through the ECR in excess of its cost of supplying that energy. Retaining the energy savings might be a reasonable policy to consider if PP&L were explicitly prohibited from recovering the non-energy costs of returning capacity. That is <u>not</u> my recommendation in this case.

A more appropriate resolution of this issue would be to permit PP&L to seek retention of the energy savings in future ECR cases based on circumstances at that time.

Q. DO YOU HAVE ANY COMMENTS ON MR. JONES' TESTIMONY CONCERNING THE MEANING OF THE <u>STRATEGY 2000</u> REPORT?

A. Yes. I can accept that different individuals within PP&L may view that study differently. The report authors emphasize the critical importance of reducing the costs of power from Susquehanna. They also express the view that the cost reduction opportunities identified in the report are feasible, prudent and must be pursued by PP&L.

In contrast, Mr. Jones explains that "[t]he identified [cost savings] initiatives represent a hypothetical solution to a hypothetical problem." (PP&L Statement 15-R, page 6) While Mr. Jones is referring in that statement to the problem of market competition, the cost burdens associated with the $3 billion Susquehanna nuclear plant are not a "hypothetical problem" for PP&L ratepayers. They are all too real.

II. PHYSICAL EXCESS CAPACITY

Q. WHAT ARE THE MAJOR ISSUES ASSOCIATED WITH THE DETERMINATION OF PHYSICAL EXCESS CAPACITY?

A. The rebuttal testimony raises numerous concerns and issues regarding the determination of physical excess capacity. The essential questions which must be addressed are:

(1) What is the PP&L planning reserve margin needed to meet an appropriate standard of reliability?

(2) Should we use a reserve margin standard for excess capacity purposes which exceeds the reserve margin target which PP&L uses (or should use) for planning purposes?

(3) Given that there is no significant disagreement over estimation of loads and resources, how should PP&L's QF capacity, interruptible load and capacity credit sales be treated in calculating physical excess capacity for ratemaking purposes?

Mr. Sipics is PP&L's primary rebuttal witness for question (1), and Dr. Hieronymus addresses questions (2) and (3). Both of these witnesses acknowledge that the Company's PJM capacity obligation of 12 percent is the appropriate lower bound, but they argue that a reasonable upper bound would be significantly higher. Neither witness identifies what he believes the appropriate reserve margin percentage upper bound to be. However, both imply that the appropriate figure may be as much as 20 percent (or more).

Reliability Standard

Q. WHAT ARGUMENTS OR CONCERNS DO MR. SIPICS AND DR. HIERONYMUS OFFER REGARDING THE APPROPRIATE RELIABILITY STANDARD?

A. They mention several factors that they believe affect PP&L's reliability of service. These include:

- reliability problems associated with extreme winter weather;

- questions concerning PP&L's long-term ability to rely upon interruptible load as a resource;
- the PJM after-the-fact capacity deficiency accounting.;
- possible impairment to reliability and the role of PJM in a competitive environment; and
- PJM's history during the last ten years with loss of load.

Q. WOULD THESE REASONS JUSTIFY A RESERVE MARGIN IN EXCESS OF 12 PERCENT?

A. No. These and other relevant factors are taken into account in PJM's decision to assign PP&L a reserve margin obligation of 12 percent. Questioning the 12 percent figure is tantamount to second guessing the adequacy of PJM's own process for determining the reliability needs of the region and pool members. There is no evidence in this case that PJM has performed this function improperly.

The proof of the pudding regarding reliability planning is PP&L's own capacity planning process. The Company's 1995 ARPR does not specifically identify a reserve margin percentage target, but one can be gleaned from the generating reserves which result from the Company's "Preferred Plan." The ARPR states at page 34:

> Based on the base case load growth projection, existing generating units are sufficient to maintain system reliability [until] at least 2008."

At page 37, the report states:

> The PP&L ARPR is based on maintaining the current level of system reliability.

Given these statements, it is clear that PP&L is projected to be surplus for the next 12 years, with the surplus eliminated by projected load growth in about the year 2007. Schedule MIK-1 reproduces information on PP&L's Preferred Plan from the 1995 ARPR for the years 2007 and beyond. PP&L projects that it may add capacity in each year (gas combustion turbines and combined cycles) after 2007 in order to keep up with load growth. In doing so, reserve margins with these capacity additions are shown as being in about the 11.5 to 12.5 percent range, clearly indicating that PP&L's target reserve margin for planning is about 12 percent. As PP&L makes clear, these reserve margins maintain "the current level of system reliability." One must assume that PP&L's reliability planning takes into account all factors mentioned by Mr. Sipics.

Q. HAS PJM EXPERIENCED EXCESSIVE PROBLEMS WITH LOSS OF LOAD AND CAPACITY INADEQUACY?

A. No, I do not believe it has. The loss of load in the winter of 1993/1994 truly was an extreme situation. PP&L witnesses also mention PJM voltage reductions in past years. These voltage reductions should not be considered to be a reliability failure by PJM. Rather, reduction in voltage, which has occurred on occasion, is properly viewed as one tool which PJM and its members have available to deal with situations which might arise a few hours per year when available reserves are very tight. This is part of the PJM protocol for preventing power shortages. Other measures to maintain reliability include having members run generating units at higher than normal capacity levels (i.e., maximum emergency generation) and curtailment of those customers taking service under a curtailable service tariff.

Q. MR. SIPICS MENTIONS THAT PJM HAS AN AFTER-THE-FACT CAPACITY DEFICIENCY TEST. IS THIS A BASIS FOR INCREASING THE TARGET RESERVE MARGIN?

A. No. First, to the extent this is a realistic concern to PP&L, it would be fully captured in PP&L's decision to plan for a 12 percent reserve margin target. Thus, PP&L itself does not see this as a reason for altering its planning process. Second there is no evidence that PP&L realistically faces any exposure to a PJM-imposed capacity deficiency penalty in either the test year or the near term. Consequently, this is not a basis for setting aside an excess capacity test.

The Ratemaking Reserve Margin

Q. WHAT ARGUMENTS HAVE COMPANY WITNESSES ADVANCED FOR USING A RESERVE MARGIN FOR RATEMAKING IN EXCESS OF THE PLANNING RESERVE MARGIN?

A. The planning reserve margin refers to minimum level of capacity reserves (expressed as a percentage of peak demand) required to meet the Company's reserve margin. In the case of PP&L, that figure is about 12 percent. That figure also corresponds to the Company's capacity obligation, as determined by PJM. Both Mr. Sipics and Dr. Hieronymus argue that this Commission should find a much higher level of reserves to be reasonable before making a finding of physical excess capacity for ratemaking purposes.

It appears that there are two basic reasons for this position. First, the PP&L witnesses assert that certain PP&L capacity resources (e.g., interruptible service and unit upgrades) were added by the Company because they were believed to be beneficial to customers. Thus, they argue that the strict use of a mechanical reserve margin calculation method would penalize the Company for taking cost-effective actions. The second argument concerns "lumpiness," i.e., the addition of units in discrete sizes which exceed annual load growth. This latter argument, if applicable, means that reserves even for a perfectly planned utility would slightly exceed the reserve margin target in some years.

Q. AS A MATTER OF POLICY, SHOULD THE RATEMAKING RESERVE MARGIN EXCEED THE PLANNING RESERVE MARGIN BY A LARGE AMOUNT?

A. As I understand the concept, an excess capacity adjustment applies the "used and useful" principle and allocates risk of excess capacity between ratepayers and shareholders. Given that purpose, it does not make sense to define a ratemaking reserve margin substantially above the planning reserve margin. As I previously indicated, a utility's planning reserve margin can vary somewhat in the short-run because capacity unit additions do not precisely match year-to-year load growth. Selecting a reserve margin percentage for ratemaking purposes above the levels the utility would seek to achieve for planning purposes only serves to negate the basic purpose of having an excess capacity disallowance policy.

Q. PLEASE COMMENT ON THE FIRST ARGUMENT CONCERNING THE ADDITION OF COST-EFFECTIVE OR OTHERWISE BENEFICIAL RESOURCES.

A. This standard would be, as a practical matter, almost impossible to implement and effectively would define away the concept of physical excess capacity. The practical difficulty arises in that the Commission would be required to review each and every capacity resource to determine why the utility added that resource and whether the resource is cost effective <u>before</u> applying the physical excess capacity test. Mr. Sipics mentions the Susquehanna upgrades and interruptible load, but there is no particular reason to stop there. Why not consider PP&L's motives in constructing its coal plants? Using this conceptual approach to the issue, physical excess capacity would lose its meaning. In essence, this is a substitution of a prudence test for a physical excess capacity test.

Q. HOW HAS DR. HIERONYMUS APPLIED THE LUMPINESS CONCEPT?

A. I understand Dr. Hieronymus' position to be that the reasonable reserve margin for ratemaking purposes should be the minimum planning reserve margin <u>plus</u> the size of the most recently added unit (or the unit which is at issue for excess capacity purposes). In this case, the "lump" is Susquehanna Unit 2, which is about 1,000 MW. Thus, the acceptable reserves before a physical excess capacity finding is reached would be 12 percent plus another 1,000 MW. Again, this has the practical effect of eliminating any excess capacity. That is, the addition of a new generating unit by itself could not be the cause of physical excess capacity.

Q. DO YOU AGREE WITH DR. HIERONYMUS' POSITION?

A. I agree that lumpiness is a consideration. As a general matter, it is impractical for utilities to precisely match capacity resource additions with load growth. Thus, when a new generating unit is added, capacity reserves may slightly exceed desired levels. It therefore may take the utility a period of time to absorb fully the capacity from the new resource (e.g., one to three years). For that reason, I have suggested that allowance of a 3 percentage point cushion over planning reserve margin may be justified.

Dr. Hieronymus' position -- that no excess capacity finding is warranted unless the surplus exceeds Susquehanna Unit 2 (e.g., 1,000 MW) -- is unreasonable. Recall that lumpiness arises as a <u>temporary</u> problem because unit size exceeds annual load growth. Given that Susquehanna Unit 2 entered service ten years ago in 1985, his 1,000 MW lumpiness allowance no longer applies. This obviously is not a matter of PP&L requiring a couple of years to "grow in" to Susquehanna Unit 2.

More importantly, it was PP&L management which made the decision to add new units in the size of 1,000 MW increments. Dr. Hieronymus would shift the risk of that decision away from PP&L and to ratepayers. According to this application of the lumpiness theory, the larger the megawatt size of Susquehanna Unit 2, the higher should be the reasonable reserve margin for ratemaking purposes. For example, if

Susquehanna Unit 2 were 1,500 MW, rather than 1,000 MW, the reasonable ratemaking reserve margin would be an even higher figure.

Q. MR. SIPICS SPECULATES THAT UNDER A FULL DEREGULATION SCENARIO, PP&L'S NEED FOR RESERVES MIGHT INCREASE ABOVE THE CURRENT PLANNING LEVEL. IS SUCH A SCENARIO RELEVANT IN THIS RATE CASE?

A. No. The measurement of physical excess capacity is properly based upon the test year and the year following. While I agree with Mr. Sipics that full deregulation raises questions regarding both reliability and the future role of power pools, under such a scenario PP&L's reserve standard would be determined by market requirements. For example, under full deregulation, the traditional utility obligation to serve might be relaxed. Thus, whether deregulation would increase or diminish a utility's reserve margin target is a matter of speculation.

Resources and Loads at Issue

Q. WHAT RESOURCES AND LOADS DO THE PP&L WITNESSES SUGGEST SHOULD BE EXCLUDED?

A. PP&L witnesses either question or dispute (1) the inclusion of NUG capacity; (2) the recognition of interruptible load; and (3) the failure to subtract capacity credit sales from PP&L's capacity.

The most important of the three issues is whether to recognize or disregard the 504 MW of NUG capacity for ratemaking. PP&L receives full capacity credit for that capacity from PJM, and the Company includes the full amount of that supply as capacity reserves for planning purposes over the 20-year planning horizon in its ARPR. Thus, for planning purposes, PP&L treats the NUG contracts as capacity resources which can provide PP&L reliable service. In that regard, there is no factual dispute. Rather, the dispute concerns whether it is fair and reasonable to recognize that capacity for ratemaking purposes, i.e., measuring physical excess capacity. PP&L witnesses argue it should not be counted, contrary to the Company's own planning practice. It must be noted that ratepayers pay the full cost of NUG contracts through the ECR.

The other two issues appear to be much less in dispute. PP&L witnesses argue that the long run reliability of interruptible load is questionable. For example, interruptible customers might revert to firm service at some future time. Despite these types of misgivings, they do not specifically recommend excluding interruptible load from the analysis (i.e., treating it as firm rather than interruptible).

A final issue concerns the treatment of capacity credit sales. As discussed in the direct testimony of Mr. Sipics and myself, these are accounting transactions among utilities for purposes of allowing potentially deficit PJM utilities, such as Baltimore Gas & Electric Company (BGE), to meet their PJM capacity obligations. These are sometimes referred to as "paper capacity" because it is a pure accounting transaction with the purchasing utility receiving no entitlement to either system or unit power supply. PP&L witnesses appear to be in conflict on this issue, with Mr. Sipics excluding capacity credit sales from his analysis, while Dr. Hieronymus argues for its inclusion (as a deduction from total capacity).

Q. WHY DOES DR. HIERONYMUS ARGUE FOR INCLUSION OF THE CAPACITY CREDIT SALES?

A. He argues that they are analogous to the interruptible service "capacity," which is factored into the PJM accounting for determining a company's capacity reserve obligation.

Q. DO YOU AGREE WITH THIS ANALOGY?

A. No, I find the analogy to be inappropriate. The interruptible service is a real, physical resource which contributes to system reliability at the PP&L and PJM level for firm service customers. That is, when PP&L/PJM finds itself in a capacity constrained situation, it can exercise the load curtailments as permitted under the tariffs thereby preserving reliability for firm customers. Thus, interruptibility may be properly viewed as a real, physical resource with operational implications for PP&L/PJM. Capacity credit sales are purely accounting transactions with no operational or reliability implications. As I have previously stated, capacity credit purchases may still be a very cost-effective means for "short" PJM utilities to meet their PJM capacity obligations.

Perhaps a better, though still imperfect, analogy would be to compare capacity credit sales to PP&L's firm capacity sales to JCP&L, Atlantic and BGE. These sales differ from capacity credit sales because (1) they are longer term (ten years or more); and (2) involve actual power supply entitlements. However, these contract sales also involve transfers of capacity accounting credits, and in that sense, they share a similarity.

Q. IF CAPACITY CREDIT SALES MAY BE IN SOME SENSE ANALOGOUS TO PP&L'S CONTRACT CAPACITY SALES, WHY NOT GIVE THEM THE SAME TREATMENT FOR EXCESS CAPACITY MEASUREMENT PURPOSES?

A. As I stated, there are both similarities and differences. Having said that, it still might be reasonable to treat the capacity credit sales as if they were contract sales, i.e., subtract the MWs from PP&L's total capacity. This would be a reasonable procedure to follow if and only if PP&L also allocates production plant to those capacity credit sales, just as it now allocates production plant out of the retail jurisdiction for the

JCP&L, BGE and Atlantic Electric contract sales. PP&L, however, allocates no production plant to its capacity credit sales, and that is why Dr. Hieronymus' position is unacceptable.

Q. SHOULD THE INTERRUPTIBLE SERVICE CAPACITY BE EXCLUDED?

A. No, and I do not understand PP&L to be proposing that. The 345 MW of interruptible service is recognized by PJM and by PP&L's own planning process. As I stated earlier, it is a "real" capacity resource which contributes to reliability.

Q. THE MOST IMPORTANT ISSUE CONCERNS NUG CAPACITY. DOES PP&L'S REBUTTAL POSITION DIFFER FROM ITS ORIGINAL POSITION ON THIS?

A. No, the arguments are essentially the same. PP&L believes that it was compelled to accept the NUG capacity and it acted prudently in obtaining PJM capacity credit. Moreover, the Company does not believe that Section 1323(c) mandates a specific Commission finding. Aside from whether there is a regulatory mandate, PP&L witnesses do not dispute my plain language interpretation of what that subsection states -- merely whether it does (and should) apply.

Q. DO YOU CONTINUE TO BELIEVE THE NUG CAPACITY SHOULD BE INCLUDED?

A. Yes. Once again, I believe PP&L's position on the NUG capacity confuses prudence with the used and useful principle. The arguments of Dr. Hieronymus and Mr. Sipics assert that PP&L did not act imprudently when adding the NUG capacity and therefore the Company should not be penalized. The excess capacity assessment is not as a general matter concerned with prudence, nor should its application be viewed as a "penalty."

I do not take a position on whether Section 1323(c) is or is not a legal mandate. Even if it is not a mandate in this case, it seems very clear that the language in that subsection provides guidance and direction on a difficult issue. That subsection grants a utility a window of up to eight years during which time the NUG capacity is explicitly excluded from excess capacity calculations. This eight-year window is fully responsive to PP&L's policy arguments. The statute obviously could have been written to exclude NUG capacity from Commission calculations for more than eight years, or even permanently, but the legislature consciously chose not to do so.

While this subsection does not explain the reason for an eight-year time limit, I believe there is a rationale for this arrangement. QF capacity is sometimes viewed as not necessarily subject to the same degree of planning control as a utility's own construction, therefore warranting special consideration in evaluating excess capacity. Permanent exclusion, however, would be extreme and would not serve to properly balance shareholder and ratepayer interests. The utility should be given a reasonable opportunity to adapt its capacity resource profile to the NUG capacity addition, and eight years is judged to be a reasonable outer bound of time for doing so. PP&L witnesses do not argue that eight years is an inadequate period of adjustment and that a longer window of time is needed.

Q. HOW COULD A UTILITY ADAPT ITS CAPACITY PROFILE TO THE NUG CAPACITY ADDITIONS?

A. An obvious example is through off-system capacity sales. As Mr. Sipics acknowledged, PP&L did not participate in either the Old Dominion or BGE competitive capacity solicitations in recent years. (OCA Request Set V, item (60)). In both cases, other nearby utilities with surplus capacity were awarded capacity contracts.

I am not arguing that PP&L has been imprudent. Rather, I am arguing that there is no persuasive reason for disregarding Section 1323(c) and the guidance it provides on this issue irrespective of whether it is a "legal mandate." The statute provides a reasonable resolution of this issue and an appropriate balancing of ratepayer and shareholder interests.

Q. PP&L WITNESSES ARGUE THAT THIS COMMISSION HAS NOT PREVIOUSLY USED RESERVE MARGINS AS LOW AS 15 TO 16 PERCENT FOR EXCESS CAPACITY PURPOSES. IS THAT A LEGITIMATE CRITICISM OF YOUR ANALYSIS?

A. No. The identification of the target reserve margin is a fact-based issue, not a policy issue. The reserve margin target will differ from one utility to another and can even change over time. The Commission bases its finding concerning the reserve margin target on the best available evidence in each case.

The PP&L target reserve margin is likely to be lower than those of other Pennsylvania utilities for a specific reason. That is, PP&L is winter peaking operating in a summer peaking power pool and is thereby permitted to save on reserves (compared to summer peaking utilities) due to its load diversity. It is also true that other utilities in PJM do not use a reserve margin as low as 12 percent for planning purposes for the simple reason that they are summer peaking. It makes no sense to ignore these crucial facts in comparing PP&L to other utilities.

PP&L witnesses point out that the Commission accepted a 22 percent standard in PP&L's last case based on the testimony before it at that time. No witness in this case specifically recommends continued application of the 22 percent standard. It should be noted that in the last case, even at 22 percent, all of Susquehanna Unit 2 was found to be excess. In that sense, identification of the target reserve margin for physical excess capacity measurement purposes was a moot issue.

III. ECONOMIC EXCESS CAPACITY

Q. DR. HIERONYMUS CONCLUDES THAT SUSQUEHANNA UNIT 2 IS NOT ECONOMIC EXCESS CAPACITY. HOW DOES HE REACH THAT CONCLUSION?

A. He conducts what might be called a "coal proxy" analysis which consists of three basic steps:

(1) calculate the year-by-year revenue requirements associated with Susquehanna Unit 2 using data supplied by PP&L;

(2) calculate the revenue requirements associated with a (multi-unit) coal plant equivalent in size to Susquehanna Unit 2; and

(3) calculate the revenue requirements difference between the two resources for each year.

The calculations are performed for a "base case" set of assumptions and for two sensitivity cases. The two sensitivity cases reduce the Susquehanna revenue requirements by allocating only 27 percent of common costs to Unit 2 (case (2)); or by assuming straight line depreciation had always been used (case (3)).

Q. WHEN DOES DR. HIERONYMUS ASSUME A COAL PLANT ENTERS SERVICE?

A. He assumes that PP&L constructs a coal plant such that it enters service in 1995. Since PP&L believes that a coal plant lead time is about eight years, this means construction would have had to begin in 1987.

Q. WHAT TIME PERIOD DOES DR. HIERONYMUS USE?

A. He uses a ten-year time period, 1995 to 2004.

Q. WHAT RESULTS DOES HE OBTAIN FOR HIS BASE CASE?

A. In general, he finds Susquehanna to be cost beneficial relative to the comparable size coal proxy. For the base case analysis, the coal plant revenue requirement cost exceeds Susquehanna Unit 2 by about $38 million per year, on average. Since Susquehanna Unit 2 provides approximately 6,750 gWh per year, this alleged cost advantage translates into about 0.6 cents per kWh.

Q. ASIDE FROM THE ACCURACY OF HIS CALCULATIONS, DOES HIS APPROACH ADDRESS ECONOMIC EXCESS CAPACITY IN A MEANINGFUL WAY?

A. Dr. Hieronymus' approach would be meaningful only if it could be shown that a new coal plant is a cost-effective (i.e., least cost) resource for the PP&L system <u>at this time</u>. More precisely, if PP&L were to remove Susquehanna Unit 2 from jurisdictional service (e.g., a ten-year off-system sale), would a new coal plant installed in 1995 be a least-cost replacement resource? Of course, all of this is hypothetical because it sets aside the question of whether PP&L could add a new coal plant in 1995 given the eight-year construction lead time for such a plant.

Dr. Heironymous does not even attempt to address the question as to whether the new coal plant, which he uses for economic benchmarking purposes is cost effective. If the new coal plant is not least cost (or approximately so), then all Dr. Hieronymus has done is compare one uneconomic resource (Susquehanna Unit 2) with a resource that is even more uneconomic (a new coal plant). Any conclusion concerning net economic benefits to customers from such a comparison is obviously erroneous.

Q. DO YOU HAVE ANY EVIDENCE ON WHETHER THE PROXY COAL PLANT IS COST EFFECTIVE?

A. While I have not had the time or data to perform an independent study, I believe PP&L's 1995 <u>ARPR</u> definitively answers that question.

PP&L conducts a screening analysis in the ARPR for a wide range of demand side and supply side resource options. Among the options considered is a 300 MW pulverized coal unit. According to PP&L's study, the coal unit provides customers with a benefit-to-cost ratio of only 0.3, indicating that it is not a cost-effective resource. In terms of dollars, the net economic penalty (present value) for ratepayers from such a unit is $604 million. Scaling that up to the size of Susquehanna Unit 2 implies a net economic penalty for ratepayers of about $2 billion (present value). Thus, Dr. Heironymous compares Susquehanna to a replacement resource with a $2 billion net economic penalty, and still finds a mere 0.6 cents per kWh cost advantage. At best, this demonstrates only that Susquehanna is marginally preferable to a resource option which is extremely uneconomic. It falls far short of demonstrating an economic benefit to customers.

Q. DOES PP&L'S ARPR SHOW THE PULVERIZED COAL PLANT TO BE THE MOST ECONOMIC OF THE BASE LOAD COAL TECHNOLOGIES?

A. No. The ARPR shows coal gasification combined cycle (CGCC) to be much more economic than the pulverized coal plant with a 0.5 benefit-to-cost ratio. In my opinion, Susquehanna Unit 2 would be far less economic than the CGCC option.

Q. DOES PP&L INCLUDE ANY NEW COAL CAPACITY IN ITS 1995 20-YEAR PLAN?

A. No. PP&L has no capacity need until 2007, and at that time and thereafter it adds only combined cycles and combustion turbines. PP&L also considers an alternative case whereby it retires over 700 MW of its current coal capacity for environmental reasons. Under that planning scenario, the 700 MW of retired coal is gradually replaced beginning in 2004, but with gas-fired units, not coal capacity. PP&L clearly views new coal plants as uneconomic resources over the next two decades.

Q. DO YOU HAVE ANY OTHER EVIDENCE?

A. In my direct testimony, I demonstrated the full cost per kWh for Susquehanna station to be about 6 cents per kWh in 1995. Given the 0.6 cents per kWh advantage implied by Dr. Heironymous, this implies a 1995 coal plant cost of approximately 6.6 cents per kWh.

Both the 6.0 and 6.6 cents per kWh greatly exceed wholesale market prices for power for five and ten year power supply contracts. In light of this, I find it surprising that a PP&L witness would assert that 6.6 cent per kWh power is a reasonable benchmark for determining whether a capacity resource provides ratepayers with near-term net economic benefits.

Q. IS THERE A PERSPECTIVE FROM WHICH THE COAL PLANT ANALYSIS MIGHT BE USEFUL?

A. Perhaps in the context of a prudence review a coal plant comparison would be useful. However, even in that case, Susquehanna Unit 2 should be compared with a coal plant entering service contemporaneously in 1985. It is an "apples and oranges" analysis to compare the costs of the ten-year old Susquehanna unit with a new coal plant.

Q. WHY DOES THIS MATTER?

A. The current and prospective rate base for Susquehanna is much lower than the rate base when the plant first entered service due to the accumulation of deferred tax and depreciation balances. The same also obviously would be true of a comparable size coal plant. Had Dr. Heironymous' proxy coal plant been built to enter service in 1985 -- rather than 1995 -- its ten year rate base value would be dramatically lower than the cost figures used in his study. This would be due to (1) the avoidance of ten years of inflation in the plant's original cost; and (2) the build up of ten years of accumulated depreciation and deferred taxes. These rate base reducing effects would be much larger than the 0.6 cent per kWh cost advantage identified by Dr. Heironymous. Had he used a 1985 rather than 1995 vintage coal plant, the cost would be perhaps 1.5 to 2.0 cents per kWh lower, more than offsetting the claimed 0.6 cent cost advantage for Susquehanna Unit 2. While I take no position on the prudence of Susquehanna, for the period 1995 to 2004, the plant is much more expensive per kWh than a 1985 vintage coal plant.

Q. PP&L WITNESSES CRITICIZE YOUR USE OF MARKET PRICES TO EVALUATE SUSQUEHANNNA. WHAT IS THE NATURE OF THEIR OBJECTIONS?

A. They seem to suggest that the use of market prices creates a new standard for judging economic excess capacity and that by doing so the OCA is pre-judging the issue of stranded costs. In addition, PP&L suggests that the 3 to 5 cent market prices (over the next ten years) are uncertain and overly conservative.

In addition, Dr. Heironymous takes issue with my estimate of capacity costs of 0.5 cents per kWh.

Q. PLEASE FIRST ADDRESS YOUR ESTIMATE OF NEW CAPACITY COSTS.

A. This is meant to be the cost of pure capacity -- assuming it is needed -- to accompany or "firm" an energy resource. According to PP&L, new capacity can be acquired at a cost of $45 per kW-year by building peaking units. (Response to OCA Set V, item 46) Thus, if PP&L needed 990 MW of replacement capacity (which it does not), it could be acquired for $45,000 x 990 = $44.6 million per year. Assuming Susquehanna Unit 2 generates 6,750,000 mWh per year (on average), this translates into $44.6 million/6,750,000, or $6 per mWh. I round this down to about $5 per mWh since $45 per kW per year is currently above market, according to Mr. Sipics.

The $5 mWh (or 0.5 cents per kWh) is pure capacity and includes no energy. Since PP&L's avoided costs are energy only, it is appropriate to add on this cost increment in order to account for capacity, when needed.

Q. PP&L CRITICIZES YOUR MARKET PRICES AS BEING UNDERSTATED AND DEPENDENT ON DEREGULATION. DO YOU AGREE?

A. I have no problem with PP&L pointing out uncertainty. That problem, of course, is present with any estimation technique. I also respect Mr. Sipics' opinion that the PP&L market price figures are conservative, although historically the problem has been the opposite -- overstating projected costs.

Several points need to be made in reply. First, whether the figures are uncertain or conservative, they represent PP&L's own best estimates. If PP&L has estimates which it believes to be more realistic, it has failed to provide them. That is, I used the only estimates which PP&L could supply -- I did not simply select the low or conservative estimates.

The second point is that the PP&L estimated market prices which I employed are broadly confirmed by other evidence. This includes (1) PP&L's own wholesale transactions; (2) other recent transactions for base load capacity between utilities in the PJM region; (3) PP&L's own estimates of its avoided costs; and (4) the busbar costs of power from a new gas-fired combined cycle unit which PP&L could construct. For example, PP&L estimates its ten year levelized avoided cost at less than 2.8 cents per kWh (all hours). (See 1995 ARPR, page 1.) To this figure, it would be reasonable to add 0.5 to 0.6 cents per kWh for capacity, for a ten-year capacity plus energy avoided cost of about 3.5 cent per kWh.

Market price estimates are not exact. But neither are avoided cost estimates, busbar costs from a combined cycle unit or cost estimates pertaining to any other resource. Precision is not the issue. Susquehanna's full cost is somewhere between 50 to 100 percent greater than the cost of power in the near term from either the wholesale generation market or other least cost sources.

Q. ARE YOU CREATING A NEW STANDARD FOR ECONOMIC EXCESS CAPACITY?

A. No. The standard is whether the base load unit provides net economic savings to ratepayers within some reasonable period of time. The market price is the price at which PP&L can either buy or sell power and therefore is a convenient way of determining whether Susquehanna Unit 2 can pass that long standing test. This test does not in any way depend on retail deregulation, although as a practical matter, non-regulated competitive wholesale generation markets exist right now.

My approach neither imposes market prices on PP&L nor does it seek a finding on stranded cost. As I demonstrated in my direct testimony, with denial of an equity return, the revenue requirement cost of Susquehanna 2 remains above market price.

Q. DR. HIERONYMUS CLAIMS THAT YOU ARE EMPLOYING A MARKET PRICING TEST FOR SUSQUEHANNA 2 BUT YOU ARE GIVING NO RECOGNITION FOR PP&L ASSETS WHOSE REVENUE REQUIREMENT COST IS BELOW MARKET. IS THIS ASSERTION ACCURATE?

A. No. In the first place, neither I nor the OCA is recommending that <u>any</u> PP&L asset be priced at market in this rate case. Second, even with my Susquehanna equity return disallowance, PP&L's cost of generation remains above market. If that were not the case, then why would PP&L be seeking permission for ECR recovery of expiring wholesale contracts? Why was it necessary for PP&L to provide substantial rate discounts to its wholesale requirements customers to retain their loads? While it is possible that PP&L may have some generation assets whose market value exceeds full cost, PP&L has not shown this to be generally true. Dr. Heironymous failed to show that any PP&L assets have market values above their book costs.

Further, while it is feasible to compare market value versus regulatory value for generation assets, such a comparison is utterly meaningless in this context for transmission and distribution (T&D). Those are monopoly functions, and there is no competitive T&D market which could be used to fairly evaluate those assets.

The fact is that Dr. Hieronymus simply disagrees with the entire concept of an excess capacity disallowance and his reference to market values in excess of book values is merely an example of his policy disagreement.

Q. DR. HIERONYMUS ARGUES THAT THERE ARE ADVERSE EFFICIENCY IMPLICATIONS FROM AN EXCESS CAPACITY ADJUSTMENT. DO YOU AGREE?

A. No. An excess capacity disallowance policy can also have an important disciplining effect on the utility and its planning process. With an excess capacity disallowance policy, utilities are encouraged to do a much better job of matching new capacity additions with load growth and to construct new capacity as cost effectively as possible.

In addition to capacity planning and construction, utilities are given enormous incentive to manage excess capacity effectively rather than sitting back, holding on to the excess and charging their ratepayers for the costs of the surplus. The most dramatic illustration of this principle is the excess capacity disallowance of Susquehanna Unit 1. In light of this disallowance, PP&L was encouraged to sell off-system the full amount of the excess (945 MW) to JCP&L.

V. ECR FLOW-THROUGH OF CAPACITY COSTS

Q. MR. KLEHA'S REBUTTAL TESTIMONY DEFENDS THE COMPANY'S PROPOSAL IN THIS CASE IN SUPPORT OF ECR RECOVERY OF CAPACITY COSTS ASSOCIATED WITH EXPIRING CONTRACTS. WHAT ARGUMENTS DOES HE OFFER IN SUPPORT OF THIS MECHANISM?

A. He claims that his proposal provides customers with two important benefits -- avoidance of rate cases and PP&L's willingness to flow back revenues from off-system sales related to this capacity. He believes this to be reasonable because the capacity costs associated with the expiring contracts "are known and measurable." Opponents of this proposal would "force" PP&L to file annual rate cases resulting in "enormous costs and regulatory burden."

He notes that one of the primary arguments of the opponents to this proposal is that it would facilitate overearning. Mr. Kleha does not believe this will occur. Moreover, consumer representatives always have the option of filing a complaint if they believe PP&L is overearning.

Q. DO ANY OF MR. KLEHA'S ARGUMENTS IN REBUTTAL MEET YOUR CONCERNS?

A. No. This approach to ratemaking is ill-advised for several reasons. The first and most important reason is that automatic cost recovery blunts incentives for cost control. In this particular case, approval of the proposed ECR mechanism would totally eliminate any incentive for PP&L to market its excess capacity. ECR recovery, as proposed by Mr. Kleha, is both easier and more lucrative. According to Mr. Kleha's logic, why stop with surplus capacity? Why not have an automatic flow through mechanism for other types of cost increases such as wages, new distribution plant and so forth?

A second objection is that PP&L's position is one-sided. PP&L would pass on the cost increase item (returning capacity) but would not recognize factors which decrease rates such as retail sales growth, savings from cost control, etc. PP&L does agree to flow through off-system sales revenues related to that capacity but such revenue is obviously not compensatory. If it were, PP&L would not be seeking this ECR recovery mechanism. Mr. Kleha's observations concerning the filing of an overearning complaint is both impractical and contradicts his assertion of savings in regulatory resources.

A third problem is that the costs themselves would not be subject to the usual review and scrutiny of a rate case. I disagree with Mr. Kleha's assertion that PP&L's generation capacity costs are "known and measurable." PP&L is contemplating a number of cost control measures for Susquehanna, as detailed in its Strategy 2000 report. The Company is unsure as to what the environmental retrofit requirements will be for its coal units. As I understand PP&L's proposal, the ECR mechanism is not just for next year. It is expected to operate for a number of years into the future, beyond the year 2000.

Q. MR. KLEHA SUGGESTS THAT IF ECR RECOVERY OF CAPACITY COSTS IS NOT PERMITTED, PP&L SHOULD BE PERMITTED TO RETAIN THE ENERGY SAVINGS. IS THIS A REASONABLE POSITION?

A. This position might be reasonable if PP&L is denied the right and opportunity to seek cost recovery for the capacity costs through standard ratemaking. That is not my position in this case. I have simply suggested here that the Company be denied the extraordinary remedy of automatic ECR recovery of capacity costs without consideration of other cost and revenue factors.

Under Mr. Kleha's new proposal, PP&L will have several ratemaking options which it can exercise as it sees fit based on whatever is most advantageous for PP&L at the time: (1) base rate recovery; (2) off-system sales in the unregulated wholesale market; or (3) retention of the energy savings below the line if the capacity is not in base rates. A blanket advanced approval of this proposal means that PP&L can selectively determine from time-to-time which ratemaking treatment is most profitable.

One possible consequence of this proposal is that PP&L could be charging its Pennsylvania jurisdictional customers through the ECR energy rates which exceed its actual cost of energy supply. And this could occur at a time when PP&L is earning more than its authorized return.

In light of these concerns, I recommend that PP&L not be granted blanket authority at this time to retain the energy savings below the line. Instead, for returning capacity which is not either in base rates or sold off-system, PP&L should retain the right to seek retention of the energy savings in individual ECR cases. Such proposals can be evaluated in each case based on circumstances at the time.

VI. THE STRATEGY 2000 REPORT

Q. WHAT IS THE PURPOSE OF MR. JONES REBUTTAL TESTIMONY?

A. Mr. Jones provides his perspective on the Strategy 2000 report, a PP&L report which I described in my direct testimony. That report provides a remaining life economic analysis of the Susquehanna nuclear plant both under current "base case" cost projections and under the assumption that PP&L adopts the many cost control recommendations identified in the report. The report suggests that busbar costs at the plant could decline by **proprietary** percent within five years if the recommendations are followed. The report finds that Susquehanna is uneconomic under the base case (i.e., the full cost exceeds market prices) but is consistent with the market under the Strategy 2000 case.

Mr. Jones' rebuttal testimony downplays the significance of the report, dismissing the cost savings initiatives as a "hypothetical solution to a hypothetical problem" and the report itself as being just "a strategic planning document, nothing more" (page 6). His rebuttal testimony questions the feasibility of some of the cost control recommendations expressing doubts about their cost effectiveness. His testimony does not actually provide any analysis or evidence on the specific cost control measures.

Q. WHAT IS YOUR REACTION TO MR. JONES' COMMENTS?

A. I am surprised by his dismissive attitude toward this vital report. This is not merely a routine consultant's report or staff document but the product of a Strategic Development Team (SDT) which interacted with top management within PP&L. The Team emphasized that an entirely new way of thinking and operating at PP&L is essential.

PROPRIETARY MATERIAL DELETED

It is clear that Strategy 2000 is not just another PP&L planning report. It urges a fundamental change in thinking for the nuclear department with emphasis on performance and cost controls at all levels.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00943271

SCHEDULES ACCOMPANYING THE

SURREBUTTAL TESTIMONY

OF

MATTHEW I. KAHAL

CONCERNING
CAPACITY ISSUES

THIS TESTIMONY DELETES INFORMATION
ALLEGED TO BE PROPRIETARY

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 1995

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

PENNSYLVANIA POWER & LIGHT COMPANY

Projected Reserve Margins, 2007-2013
(MW)

Year	Net Capacity Resources	Net Winter Peak Demand	Reserve Margin
2007	9,009	7,990	12.75%
2008	9,149	8,125	12.60
2009	9,289	8,260	12.46
2010	9,419	8,405	12.06
2011	9,559	8,540	11.93
2012	9,699	8,675	11.80
2013	9,829	8,820	11.44

Source: Annual Resource Plan Report for PP&L (May 1, 1995). See page 2 of this schedule.

Company Name: Pennsylvania Power & Light Co.

IRP-ELEC 2B. Estimated Winter Peak Resources, Loads and Reserves (MW)

		Resources							Peak Load				Reserve		
Index Year (a)	Actual Year (b)	Total Capability (c)	Inoperable Capability (d)	Operable Capability (e)	Non-Utility Generators (f)	Scheduled Imports (g)	Scheduled Exports (h)	Net Resources (i)	Total Internal Peak Load (j)	Interruptible Load (k)	Load Management (l)	Net Internal Peak Load (m)	Reserve Margin (n)	Scheduled Maintenance (o)	Adjusted Margin (p)
-5	1990	8468	0	8468	499	15	1070	7912	5704	0	43	5661	2251	0	2251
-4	1991	8498	0	8498	499	0	1200	7797	6001	73	27	5901	1896	0	1896
-3	1992	8498	0	8498	504	0	1200	7802	6136	107	6	6023	1779	0	1779
-2	1993	8498	0	8498	504	0	1200	7802	6406	223	3	6180	1622	0	1622
-1	1994	8543	0	8543	504	0	1203	7844	6514	290	6	6218	1626	0	1626
0	1995	8540	0	8540	474	0	1206	7808	6736	290	10	6436	1373	0	1373
1	1996	8540	0	8540	474	0	1017	7997	6804	290	14	6500	1497	0	1497
2	1997	8588	0	8588	474	0	828	8234	6933	290	18	6625	1609	0	1609
3	1998	8588	0	8588	474	0	639	8423	7074	290	24	6760	1663	0	1663
4	1999	8570	0	8570	474	0	450	8594	7214	290	29	6895	1699	0	1699
5	2000	8552	0	8552	474	0	132	8894	7369	290	29	7040	1854	0	1854
6	2001	8552	0	8552	474	0	0	9026	7494	290	29	7175	1851	0	1851
7	2002	8552	0	8552	474	0	0	9026	7629	290	29	7310	1716	0	1716
8	2003	8552	0	8552	474	0	0	9026	7774	290	29	7455	1571	0	1571
9	2004	8552	0	8552	474	0	0	9026	7904	290	29	7585	1441	0	1441
10	2005	8535	0	8535	474	0	0	9009	8039	290	29	7720	1289	0	1289
11	2006	8535	0	8535	474	0	0	9009	8174	290	29	7855	1154	0	1154
12	2007	8535	0	8535	474	0	0	9009	8309	290	29	7990	1019	0	1019
13	2008	8675	0	8675	474	0	0	9149	8444	290	29	8125	1024	0	1024
14	2009	8815	0	8815	474	0	0	9289	8575	290	25	8260	1029	0	1029
15	2010	8945	0	8945	474	0	0	9419	8718	290	23	8405	1014	0	1014
16	2011	9085	0	9085	474	0	0	9559	8851	290	21	8540	1019	0	1019
17	2012	9225	0	9225	474	0	0	9699	8984	290	19	8675	1024	0	1024
18	2013	9355	0	9355	474	0	0	9829	9127	290	17	8820	1009	0	1009
19	2014	9355	0	9355	474	0	0	9829	9270	290	15	8965	864	0	864

OCA Statement No. 4A
R-943271 5/26/95
Hbg TK

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket Nos. R-00943271
PENNSYLVANIA POWER & LIGHT COMPANY	:	

Surrebuttal Testimony and Exhibits
of
Dale G. Bridenbaugh

On Behalf of
Pennsylvania
Office of Consumer Advocate

May 19, 1995

OCA Statement No. 4A

SURREBUTTAL TESTIMONY OF DALE G. BRIDENBAUGH

Q: What is your name and title?

A: My name is Dale G. Bridenbaugh. I am the President of MHB Technical Associates and a Principal Consultant with the firm. I am appearing as a consultant for the Pennsylvania Office of Consumer Advocate (the OCA).

Q: Have you previously testified in this proceeding?

A: Yes. I authored OCA Statement No. 4, which was filed by the OCA, and I was cross-examined on that direct testimony on May 3, 1995.

Q: What is the purpose of your Surrebuttal Testimony?

A: The purpose of this testimony is to respond to the prefiled Rebuttal Testimony of Thomas S. LaGuardia which has been submitted as PP&L Statement 13-R.

Q: What issues does Statement 13-R address?

A: Mr. LaGuardia's Rebuttal Testimony addresses adjustments proposed by various witnesses in this case concerning the decommissioning of the Susquehanna Steam Electric Station (SSES) and concerning the decommissioning of several of the Company's fossil plants.

Q: Which of those issues does your Surrebuttal Testimony address?

A: My testimony is limited to only those issues contained in Statement 13-R which deal with the decommissioning of the SSES. Each of the major elements contained therein are addressed in turn in the following portions of my testimony.

NON-RADIOLOGICAL DECOMMISSIONING

Q: At page 4 of Statement 13-R, Mr. LaGuardia states that PP&L would have to do much more than fencing and guarding the SSES remaining facilities if non-radiological decommissioning is not carried out, and implies that this might be more expensive than the complete removal as is assumed in his cost study. Do you have any response to that stated position?

A: Yes. I believe that if PP&L does in fact totally abandon the Susquehanna site as a working generating facility, it may be advantageous in the long run to tear down all structures and restore the site as assumed by the TLG Study. However, as I state in my original direct testimony, I do not believe that is what the ultimate use will be of this valuable property. It was selected, after a lengthy decision process, as an optimal location for generation and transmission of electrical energy, and it will continue to be suitable for that purpose long after SSES ceases operation.

It may be that there will be a transition period between cessation of SSES operation and the development of a new PP&L facility. Until it is determined what that new facility will be, and which of the existing structures may be useable, it is my opinion that the existing protective fencing with protective guard personnel in place would suitably protect the public at a minimal cost.

Q: Mr. LaGuardia states at page 4 that his study "does not provide for the removal of the basic structures for which it is reasonable to believe that a useful purpose will exist after decommissioning." Do you agree with that statement?

A: No, and it seems totally inconsistent with the decommissioning study as submitted with Mr. LaGuardia's original testimony (Exhibit TSL-2). That Study, at page 4-7, indicates that "(a)lthough not required for license termination, it is assumed that the site is restored by regrading the site to conform to the adjacent landscape."

Further, at page 4-11, it states that "(a)ll structures and site improvements will be removed to three feet below local grade and the terrain restored to the local grade level." Thus, it would appear that, other than the electrical switchyard and site drainage control he lists, his study includes the removal of all structures, regardless of possible future use.

Q: Mr. LaGuardia also states at page 4 of his Rebuttal Testimony that his SSES cost study includes the cost of dismantling only those structures located within the perimeter of the "restricted area". How many structures are located outside of the "perimeter of the restricted area"?

A: Essentially none. Attached as **Figure 1** and **Figure 1a** are copies of a SSES site plan showing the location of the various structures. [1] All of the major structures identified thereon, and many minor structures not identified, are listed in the TLG study as being slated for removal, even though some of them are not within the "restricted area" as it is commonly defined by the NRC. Attached as **Table 1** is a listing of the buildings identified in the TLG backup papers scheduled for removal and included in the cost estimate. [2] It seems to include all structures associated with the SSES plant, many of which would not be expected to be radioactive nor to contain radioactive materials. Even the warehouse, roads and parking lot, some of which arguably could be said to be outside of the "restricted area," are scheduled for removal or for "cover with fill." [3]

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[1] Both these Figures are taken from the NRC's Nuclear Power System Sourcebook for Susquehanna 1 & 2. The identification labels for buildings are difficult to read on Figure 1 so Figure 1a is being provided to assist in deciphering the legends.

[2] Building Inventory Listing provided in Volume I of the Supplemental Backup Support for TLG Engineering, Inc., Document PO2-25-001 (Unit 2), provided as Response to OCA II-1.

[3] The warehouse is planned to be used by the decommissioning contractor and dismantled when no longer needed (page 4-10 of Exhibit TSL-2). Roads and parking areas will have paving materials removed and then covered with fill (page 4-11).

FIGURE 1

Site Facilities Plan

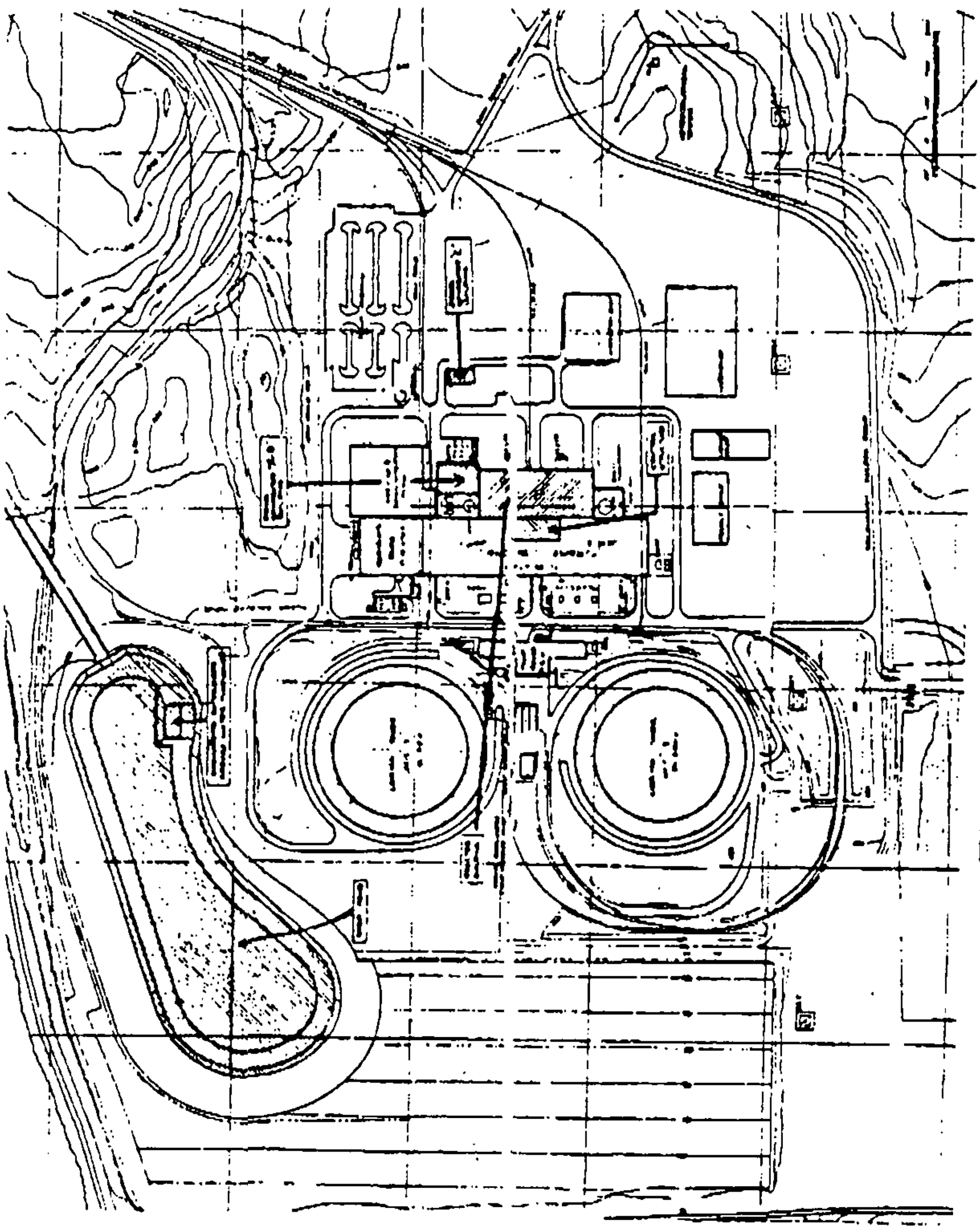

Figure 4-1. General View of the Susquehanna Site and Vicinity

FIGURE 1a

Site Facilities Plan

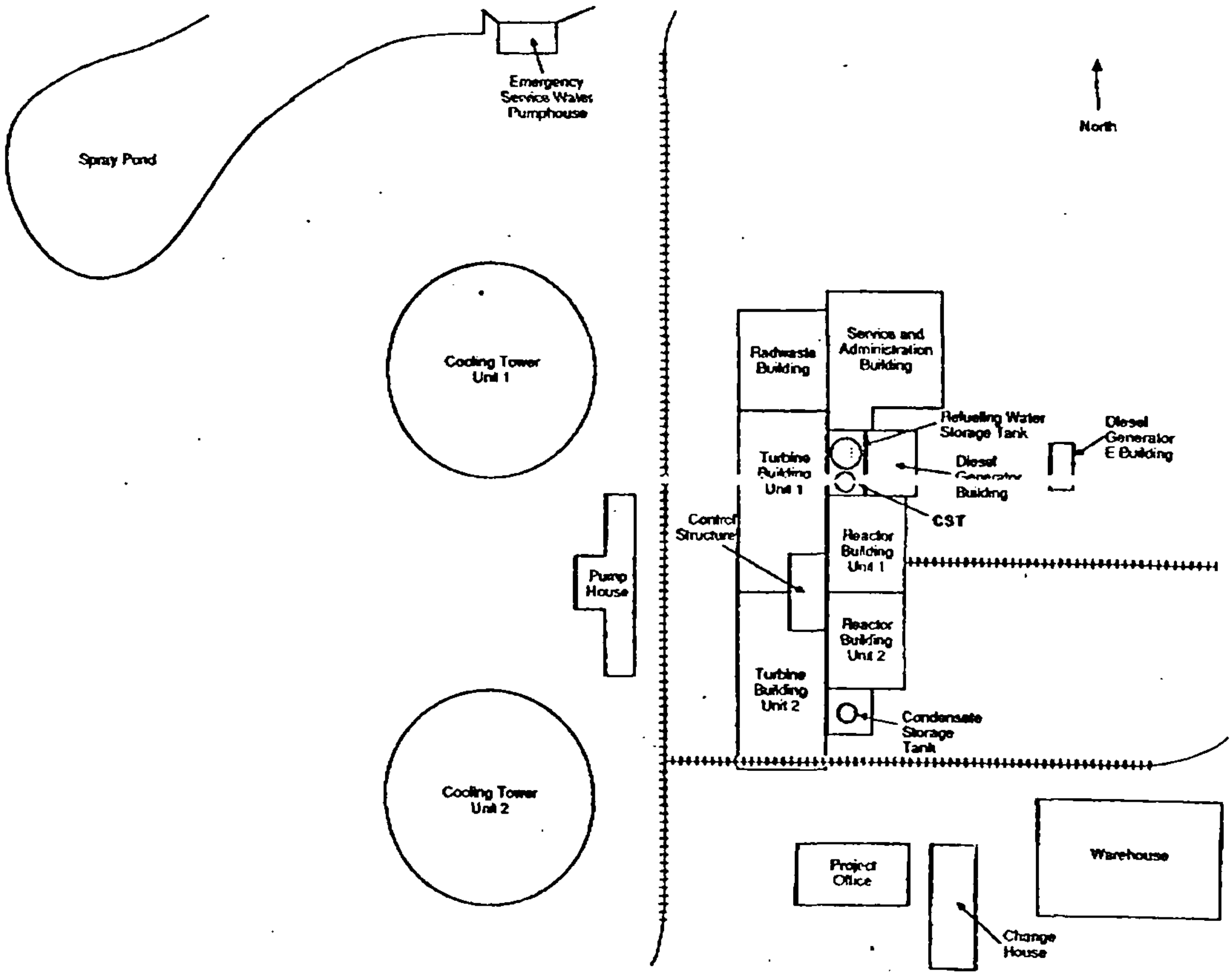

Figure 4-2. Susquehanna 1 and 2 Simplified Site Plan

TABLE I

Building Inventory Listing

Susquehanna Steam Electric Station Unit 2

(Source: TLG Supplemental Backup)

The following buildings are designated for removal:

Administration Building
Carpenter Shop
Changehouse
Chlorine Evaporator & Sulfuric Acid Storage Building
Circulating Water Pumphouse & Water Treatment Building
Combination Shop
Control Structure
Cooling Tower
Diesel Generator Building
Diesel Generator "E" Building
Domestic Fire Water Pumphouse
Engineered Safeguard & Spray Pond
Hazardous Waste Storage Facility
Health Physics Access Building
Intake Transformer Foundation
Low Level Radwaste Facility
Miscellaneous Structures
Miscellaneous Yard Structures and Foundations
North and South Gatehouses
Project Office
Radwaste Building
Reactor Building
River Intake Structure
Security Control Center
Service & Administration Building
Sewage Treatment Plant
Training Center
Transformer Foundations
Turbine Building
Underground Fuel Tanks
Warehouse
Waste Management Facility
Welder Testing Shop
Yard Tanks & Foundations

Q: Mr. LaGuardia also states at page 3 that the NRC has "dictated site restoration activities as part of the nuclear licensing process" in some instances, and thereby infers that the NRC does have interest in the removal of non-radiological facilities at the SSES. Do you agree with this position?

A: No. As I stated in response to a cross-examination question on this subject on May 3, 1995, my recollection of such instances is that the NRC only made such rulings in conjunction with the cancellation of a second unit at a two-unit site. I believe that the site restoration activities in those cases, if any, was ordered because of the effect of the canceled unit on the results of the environmental impact assessment conducted in the initial licensing review. It has nothing to do with the NRC requiring that the SSES site be returned to its original condition at the time of decommissioning. Thus, those NRC decisions are irrelevant to the questions raised in this proceeding.

Q: At page 5 of Statement 13-R, Mr. LaGuardia claims that "any attempt to quantify the costs and benefits of specific site plans thirty to forty years into the future would be a meaningless exercise". Can you comment on that statement?

A: Yes. I find it somewhat ironic that Mr. LaGuardia makes such a statement when the subject he testifies to is a very similar study, namely the decommissioning of the SSES plant which will not be completed, under the most optimistic of circumstances, until 2033, some 38 years in the future. Even though it is a long time into the future, it is incumbent on the utility to attempt to develop a plan and quantify the effects of that plan so that the current and future ratepayers are fairly treated.

CONTINGENCIES

Q: At pages 5 and 6 of his testimony, Mr. LaGuardia suggests that his experience in the decommissioning of the Shippingport facility justifies the level of contingency he includes in the SSES cost estimate. Do you agree?

A: No. Although Mr. LaGuardia's Rebuttal Testimony is silent on the numerical amount of contingency used at Shippingport, as reported by the U.S. DOE, decommissioning costs there came in some 8% below budget, when the contingency is included.

The contingency amount included in the Shippingport decommissioning cost estimate was $11.6 million of the total $98.3 million estimate. This equates to a 13 percent contingency factor. Since the actual cost of Shippingport decommissioning was $91 million, only $4.3 million of the contingency was used. Therefore, the actual contingency used was 5% of the base estimate. [4] This can be compared to the overall contingency of approximately 18% that has been applied in the TLG estimate of the SSES costs.

Q: At page 6, Mr. LaGuardia claims that the "decommissioning activities" at the Yankee Rowe, Shoreham, Pathfinder and Rancho Seco plants have "confirmed" the "accuracy of TLG's estimates". Do you believe that to be the case?

A: No. I think Mr. LaGuardia's claim is premature and/or unfounded.. Of the four plants listed, only one, Pathfinder, has been completely decommissioned, and that plant was small and of an atypical design, as was implied by Mr. Gadsden in his cross-examination of me. [5] As to the other three plants, the actual decommissioning is not nearly complete or is not relevant to the decommissioning

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[4] See **Exhibit DGB-13** attached.

[5] TR-1771.

of the SSES. First, the Yankee decommissioning plan was only just approved by the NRC in February of this year. Further, that plan is based on the SAFSTOR option, with major work to be delayed until a LLRW disposal site is available sometime after 2000. [6] This means that the bulk of decommissioning work is at least five to ten years off in the future.

Second, the Rancho Seco decommissioning plan was approved by the NRC on March 20, 1995, less than two months ago. Accordingly, very little physical work has been done as of now. It is also informative to note that even though the plan has been approved by the NRC, the NRC's approval order states that the decommissioning plan is to be updated at least every two years. [7] From that experience, it is far too early to say it confirms anything other than the development of a plan acceptable to the NRC.

Finally, with respect to the Shoreham decommissioning, it is almost totally inapplicable to the decommissioning of the SSES plant which will have been operated for years at full power.

Q: Why is that?

A: Shoreham is a BWR similar in configuration to Susquehanna, but it was never operated at greater than 5% power, and it only operated a few days at that level. The total operating time it achieved was the equivalent of two effective full power days. This means that much of the equipment and facilities at Shoreham were only mildly radioactive or were not at all contaminated. The "unique aspects" of the Shoreham decommissioning are illustrated by a visual aid prepared by the U.S.

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[6] The SSES decommissioning cost requested in this proceeding is based on the DECON (prompt removal) option.

[7] U.S. NRC Order Approving the Decommissioning Plan and Authorizing Decommissioning of the Facility, 3/20/95, p. 4.

NRC and used in a public information meeting held in December 1995. [8] A copy of this aid follows as **<u>Figure 2.</u>** It emphasizes the effect of the minimal operating time on the radiological conditions of the plant. The Shoreham decommissioning was "completed" by removing only portions of the nuclear system, including the reactor vessel and internal components and some of the piping, and by shipping the nearly new reactor fuel to PECO's Limerick site for use in that facility. [9] An example of this partial removal is found in an October 1994 NRC Inspection Report which indicates that an "extensive amount" of embedded and exposed pipe (approximately 16,000 feet) has been left in place. [10]

Another measure of the uniqueness of the Shoreham decommissioning can be obtained by comparing the amount of material removed from the site at Shoreham with the amounts estimated for only Unit 2 at the SSES. The TLG cost study for the SSES concludes that a total of 35,712 tons of <u>scrap metal</u> will be removed from Unit 2 (Unit 1 will contribute another 11,409 tons). [11] The Shoreham decommissioning resulted in the shipment offsite of a total of only 2,127 tons of material. This consisted of both LLRW, and pressure vessel segments, which were shipped to a licensed smelter. The Shoreham total is less than 6% of the expected SSES Unit 2 <u>scrap metal</u> amount. [12]

Q: What is happening to the rest of the facility?

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8 Taken from Attachment 3 to the U.S. NRC Inspection Report No. 50-322/94-05, January 27, 1995.

9 See the NRC Policy Issue No. SECY-95-025 dated February 3, 1995, copy appended as **<u>Exhibit DGB-14</u>**.

10 U.S. NRC Inspection Report No. 50-322/94-04, October 20, 1994, p. 13.

11 Exhibit TSL-2, pages C-9 and C-18.

12 U.S. NRC Inspection Report No. 50-322/94-04, 10/20/94, p. 8.

UNIQUE ASPECTS OF SHOREHAM DECOMMISSIONING

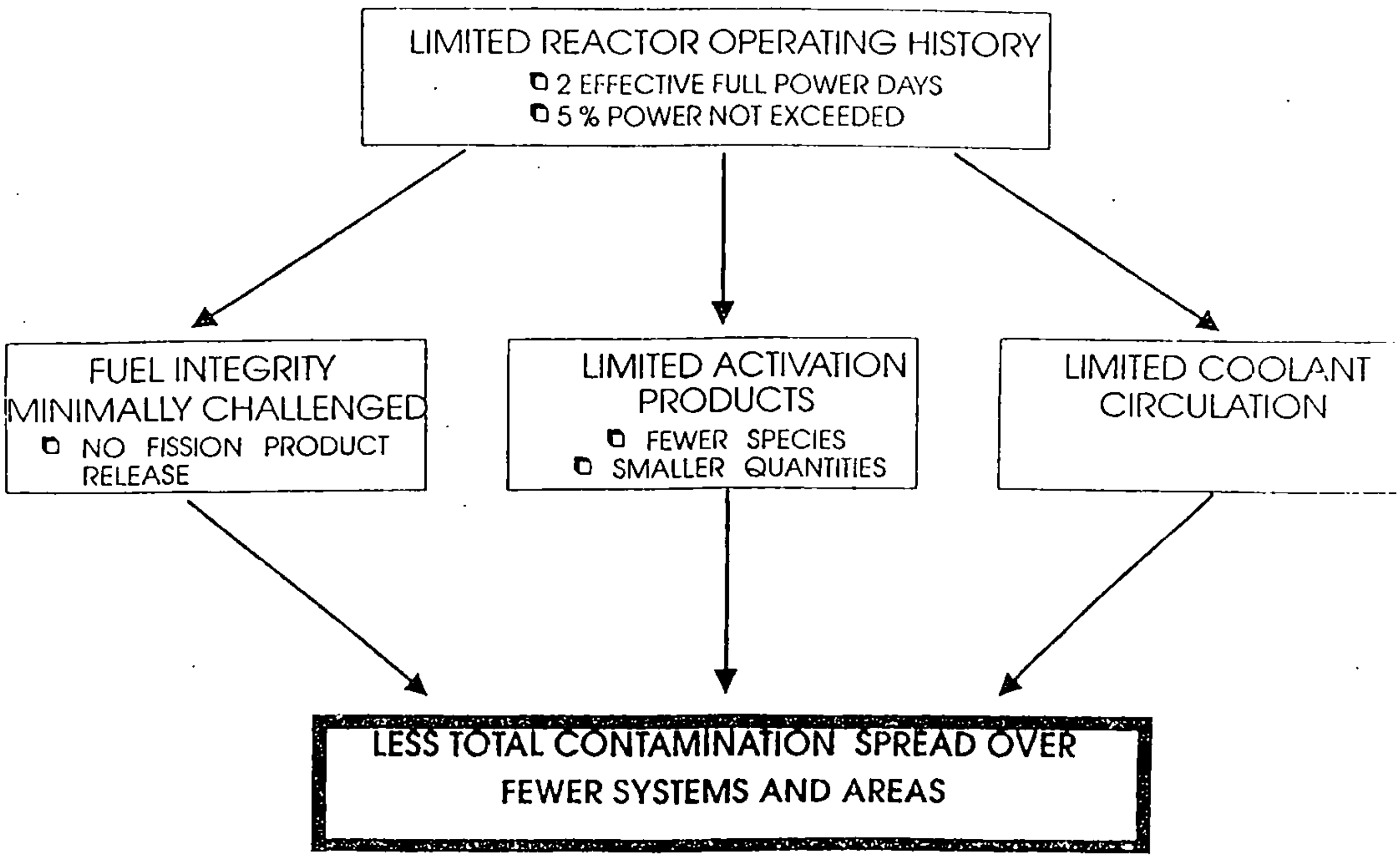

FIGURE 2

A: The bulk of the equipment and structures have been decontaminated and remain in place. The utility is undertaking a worldwide marketing effort to sell much of the equipment which is still potentially useable. [13] I conclude that it is too soon to draw any broad conclusions from the Shoreham experience.

LOW LEVEL RADIOACTIVE WASTE DISPOSAL

Q: Mr. LaGuardia discusses at some length at pages 6 through 11 of his testimony the reasons he believes his use of the Barnwell waste disposal unit cost, including the addition of a surcharge, is appropriate. Do you have any comments on that subject?

A: Yes. My original direct testimony pointed out the very speculative nature of such costs, and identified the wide ranges of disposal costs that have been used in various studies and accepted by various jurisdictions. See in particular pages 25-27 of OCA Statement 4 and the associated **Exhibit DGB-6**. Mr. LaGuardia argues for, on page 11 of his Rebuttal Testimony, a unit disposal cost of approximately $300 per cubic foot, and likens that cost to the $279 per cubic foot he has used. [14] While there is no disagreement that costs have increased from the $36 per cubic foot unit cost generally used by TLG in 1989 estimates, Mr. LaGuardia's Rebuttal Testimony focuses only on the high end of the cost ranges. [15]

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[13] See *Inside NRC*, page 5 & 6, February 20, 1995.

[14] Mr. LaGuardia's $279/ft.^{3} unit cost is further escalated by adders and contingency.

[15] See OCA Statement 4, page 25 and **Exhibit DGB-8** for unit costs used in other studies and approved plans.

An additional point that I would like to make is that I did not testify that a unit cost different from TLG's $279 per cubic foot should be used, rather, I testified that the LLRW disposal costs were highly uncertain, that they could either increase or decrease, and therefore it is not reasonable to further increase them by the use of contingencies. This position was also endorsed by a chapter in the Energy Journal's Special Nuclear Decommissioning Issue.[16] This article was written by three Pacific Gas and Electric employees, and presents a model of the risks of under and over-collection. They reached the following conclusion:

> The major uncertainties [in decommissioning] are derived from the fact that: (1) no major nuclear plant has ever been decommissioned; and (2) implementation will occur well into the next century. This means that even the best engineering and construction costs and funding estimates must involve a high degree of risk. We have noted above that there were risks of under- and overestimation for costs and funding. Combining the normal funding policies plus adding contingency probably will result in a surplus. This surplus, in turn, will have negative efficiency implications; plus it will penalize current ratepayers." (Emphasis added).

Q: Have you seen other recent LLRW cost estimates that support your view that costs could be lower as well as higher?

A: Yes. The Cleary study which was appended as **Exhibit DGB-6** to my original testimony shows a wide range of LLRW costs, both higher and lower, which are currently being considered. Of particular relevance is the last page of **Exhibit DGB-6**, which shows the sensitivity of LLRW unit costs to the volume of waste to be handled at the facility. The economics of this effect may very well result in the future combining of some of the various compacts' disposal sites, reducing the expected future site costs. Another such study that I am aware of was performed

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[16] Martin Pasqualetti, Geoffrey Rothwell Ed., Nuclear Decommissioning Economics: Estimate, Regulation Experience and Uncertainties, Chapter 3, Volume 12, Special Issue, 1991. "Utilities and Decommissioning Costs: The Meeting of Technology and Society," Ballard, Everett et. al., p. 40.

in conjunction with the Seabrook decommissioning cost study in 1993. This study arrived at a unit disposal cost of $160 per cubic foot, and was used in Mr. LaGuardia's cost estimate that was prepared for the Seabrook operator, North Atlantic Energy Co. [17] I am attaching as **Exhibit DGB-15** a copy of the statement of Jene N. Vance which was submitted in New Hampshire to describe the derivation of the LLRW unit cost update as used in the TLG decommissioning study of the Seabrook plant. The Vance statement concludes, in 1993 dollars, that the LLRW disposal charge for the decommissioning cost estimate for Seabrook should be $160 per cu. ft. This assumes a small-to-moderate sized facility employing an underground vault system. It further indicates that the $220 surcharge then being paid to Barnwell would not apply to Seabrook wastes, since disposal would be at a future and unidentified disposal site. That surcharge is obviously also not applicable to SSES.

Q: In his discussion of LLRW unit costs, Mr. LaGuardia cites unit costs that have been accepted in other jurisdictions. Does this make them acceptable in Pennsylvania?

A: No. As I have stated above, and as previously stated in my direct testimony, I think that waste costs could change significantly in either direction. My previously filed **Exhibit DGB-8** shows the wide variation of unit costs that have been accepted in different jurisdictions, many of which are lower than the cost used by TLG at SSES.

Q: At page 11 & 12 of his testimony, Mr. LaGuardia states that the use of the SAFSTOR decommissioning option would not be significantly different in cost from the DECON option. Do you agree with that conclusion?

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[17] See Response to OCA-II-4, previously submitted in this case as **Exhibit DGB-8**.

A: No, I do not think that this option has been given adequate consideration to support that conclusion. Importantly, while there may be no large effect to the ultimate volume of LLRW as a result of the longer decay period inherent with SAFSTOR, there could be significant changes in decommissioning and/or decontamination technology that would make large differences in the ultimate costs of the two options. Improved procedures and equipment could significantly reduce the overall future cost of decommissioning for the longer time frame associated with the SAFSTOR option. Also, the longer time period available for growth of the escrow fund may possibly permit a reduction of the annual accrual rate.

Q: Does Mr. LaGuardia's Rebuttal Testimony cause you to change any of the recommendations contained in your Statement No. 4?

A: No. I believe the recommendation I made to remove the costs associated with the non-radiological decommissioning and the contingency is still appropriate. I believe that there is a reasonable possibility that LLRW disposal costs will decrease and that this possibility should be taken into consideration when determining whether an overall contingency factor is needed.

Q: Does this complete your testimony?

A: Yes.

EXHIBIT DGB-13

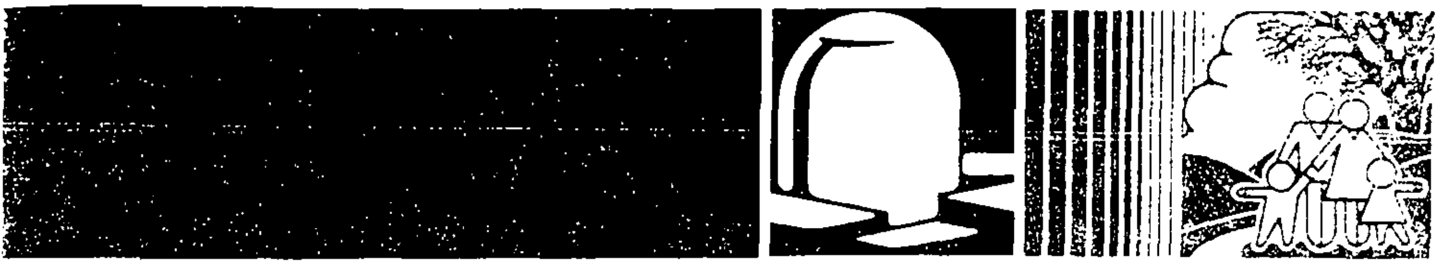
FINAL PROJECT REPORT

SHIPPINGPORT STATION DECOMMISSIONING PROJECT

EXECUTIVE SUMMARY

DECEMBER 22, 1989

SHIPPINGPORT STATION DECOMMISSIONING PROJECT



FINAL PROJECT REPORT

SHIPPINGPORT STATION DECOMMISSIONING PROJECT

December 22, 1989

Prepared for the:

U.S. Department of Energy
Richland Operations Office
Shippingport Station Decommissioning Project Office

Prepared by:

Westinghouse Hanford Company
Shippingport Station Decommissioning Project Office
Post Office Box 323
Shippingport, Pennsylvania 15077
Under Contract DE-AC06-87RL10930

EXECUTIVE SUMMARY

The SSDP mission was to make the nuclear portion of the Shippingport Atomic Power Station safe from a radiation statndpoint. In order to support this mission the following objectives were established:

a) Demonstrate safe and cost effective dismantlement of large full scale nuclear fueled electric power plant.
b) Optimize number of subcontractors to induce a transfer of decommissioning experience to the nuclear industry.
c) Provide for technology transfer by generation of project performance data and documentation of decommissioning experience for use in future decommissioning projects.

The technical approach for the SSDP was to:

1. Remove all government owned structures to three feet below grade.
2. Dispose of all nuclear waste at the U.S. Department of Energy Hanford Reservation.
3. Remove and ship the Reactor Pressure Vessel/Neutron Shield Tank as a single component.
4. Release the site for unrestricted use and return it to the owner, Duquesne Light Company.

The total estimated cost, including planning, was $98.3 million with an operations schedule planned to commence in September 1984 and to conclude in April 1990. Final costs under-ran by $7.0 million for a total of $91.3 million with actual project operations being completed in September 1989. Physical decommissioning occurred over forty six months from September 1985 to July 1989. The lease to the property was returned to Duquesne Light Company by DOE on December 29, 1989 with a certification of availability for unrestricted use.

The most significant part of the Shippingport project was the one piece removal of the Reactor Pressure Vessel (RPV) package and its 8400 statute mile shipment. The total cost to prepare, to remove, and to bury the package was $10.3 million. Work included in this was: re-positioning the non-fuel reactor internal components in the RPV; filling the RPV cavity and the NST annulus with an engineered grout mixture; developing and writing a Safety Analysis Report for Packaging; removing the RPV package as a single package, then loading and transporting the package to Hanford for burial; and, coordination of shipment and state notification activities.

All other government owned structures on site were removed to at least three feet below grade and all radioactive waste generated during decommissioning was transported to and buried on DOE's Hanford Reservation. Total volume of radwaste buried was 214,000 cubic feet (4,200 tons). Trucks were used for 200 radwaste shipments to Hanford while eight railroad gondola cars were used for a single shipment of large unsegmented and self contained components such as: pumps, valves, heat exchangers, tanks, steam drums and the pressurizer. An ocean going barge was used for shipment of the RPV package. Other non-radioactive hazardous chemical and toxic wastes (primarily asbestos) were disposed of through licensed vendors and disposal sites.

Although Site Release criteria were based on a dose of 100 mrem/yr to the maximum exposed individual far less is predicted (2 mrem/year for the worst case). Field radiation surveys to support this prediction were subject to independent verification and are described in comprehensive documentation.

Four major lessons learned were: 1) the reactor pressure vessel one piece removal is a cost effective and practical procedure; 2) the nuclear industry's present labor force and management can undertake decommissioning with no need for huge sums of money nor extended application of manpower and effort; 3) management's strict attention to ALARA practice, planning, and scheduling leads to reductions of occupational radiation exposure and concurrently to efficient removal of radioactive components; and, 4) existing equipment and technology can easily accomplish decommissioning.

Appendix A contains a list of technology transfer materials and information.

EXHIBIT DGB-14

NRC POLICY ISSUE NO. SECY-95-025

DATED FEBRUARY 3, 1995

2/9/95

POLICY ISSUE
(Information)

February 3, 1995

SECY-95-025

FOR: The Commissioners

FROM: James M. Taylor
Executive Director for Operations

SUBJECT: TERMINATION OF SHOREHAM NUCLEAR POWER STATION OPERATING LICENSE

PURPOSE:

To inform the Commission that the decommissioning process has been completed at the Shoreham Nuclear Power Station (SNPS), Unit 1, located in Suffolk County, New York, and that the staff plans to issue an Order terminating the Nuclear Regulatory Commission Nuclear Power Facility License No. NPF-82 (NRC Docket File No. 50-322), and authorizing the release of the site for unrestricted use.

SUMMARY:

The SNPS facility was formerly a single-unit boiling-water reactor (BWR) nuclear power facility that was designed to produce a gross electrical output of 849 megawatts (849 MWe). The facility was operated for testing from 1985 through 1987 for the equivalent of approximately 2 effective full-power days, without ever exceeding 5 percent of its rated operating power. The unit was prematurely shut down and the reactor was defueled in 1989, after the original owner and licensee, Long Island Lighting Company (LILCO), reached a settlement agreement with the State of New York to transfer plant ownership and the NRC license to the Long Island Power Authority (LIPA) for decommissioning. LIPA was established to decommission

Contact: Clayton L. Pittiglio
415-6702

NOTE: TO BE MADE PUBLICLY AVAILABLE IN 5 WORKING DAYS FROM THE DATE OF THIS PAPER

9502140014

the facility and release the site for unrestricted use. The full-power operating license (No. NPF-82) was amended to a possession-only status in July 1991 and was subsequently transferred, as amended, to LIPA in February 1992. NRC approved the decommissioning plan in June 1992; the plan approved decontamination or removal of contaminated portions of the reactor and other plant systems. LIPA is the current owner and licensee of the facility.

The limited period of reactor operation resulted in activation and contamination of various components, systems, and structural areas within the plant. Decommissioning began in June 1992 and was completed in August 1994. The slightly irradiated fuel was shipped to the Limerick Generating Station for reuse.

The licensee conducted termination surveys to assess residual radioactive contamination levels at the facility. Phase 1 was the termination survey of the internal components of the main turbine, turbine building, site grounds, and exterior site structures. Phases 2 and 3 surveyed portions of the reactor building, the suppression pool, and the radwaste building. The fourth and final phase surveyed the portions of the reactor building that had been used to store fuel before it was shipped to Limerick. LIPA completed the final radiological survey in August 1994.

Oak Ridge Institute for Science and Education (ORISE), under contract to NRC, conducted a series of independent confirmatory surveys, during four site visits, from February 1993 through November 1994, to verify the accuracy of LIPA's survey. For its confirmatory survey, ORISE selected 46 licensee-designed survey units. The 46 confirmatory survey units consisted of 23 randomly selected affected survey units, 14 randomly selected unaffected survey units, and 9 specifically selected affected and unaffected survey units. The ORISE confirmatory survey affirmed the licensee's final survey results. On the basis of the licensee's completion of decommissioning activities, the NRC staff's review of the licensee's termination survey report, and the results of NRC confirmatory surveys, the staff concludes that the site is suitable to be released for unrestricted use.

BACKGROUND:

The SNPS facility site is located in the town of Brookhaven, Suffolk County, New York, about 50 miles east of New York City on the north shore of Long Island. The developed portion of the site, which contains the Shoreham plant structures, several blacktop or gravel parking areas, intake canal, discharge tunnel, barge dock, and numerous ancillary structures, comprises approximately 80 acres. Approximately 18 acres of the site's developed area was in use during the decommissioning. The balance of the site remains the property of LILCO.

The SNPS facility was constructed as an 849 MWe nuclear power plant. The plant contained a General Electric (GE) model BWR nuclear steam supply system with a rated core thermal power of 2436 MWt within a GE Mark II (pressure-suppression)-type containment in the reactor building, and coupled to a GE turbine generator located in the turbine building. The first and only reactor core fuel load consisted of 560 GE-BWR6 fuel assemblies, each of which was made up of 64 individual Zircalloy fuel rods containing uranium dioxide fuel pellets.

SNPS achieved initial criticality in February 1985. A low-power operating license (not to exceed 5-percent power) was granted in July 1985. The plant was tested intermittently at low power levels (not exceeding 5 percent) over the course of approximately 2 years. After operating for the equivalent of approximately 2 effective full-power days, the reactor was shut down in June 1987. A full-power operating license was granted in April 1989. As a result of a settlement agreement reached with the State of New York in February 1989, the licensee (LILCO) agreed not to operate the plant and transferred ownership and the Part 50 license to LIPA.

The fuel, the control rod blades, as well as a number of other in-core components and sealed radioactive sources, were removed from the reactor and placed in the spent fuel storage pool (SFSP) in August 1989. In June 1991, the full-power operating license was amended to a possession-only license, and the license was transferred to LIPA in February 1992.

The operating history of the plant, although very limited, resulted in the irradiation of the nuclear fuel and activation of structures and components in the reactor vessel and contamination of systems, components, and areas within the facility. Portions of the steel reactor pressure vessel (RPV), the steel-lined concrete reactor bioshield wall, and many of the RPV internal components were activated to varying degrees, and all or portions of 13 plant piping systems external to the RPV became contaminated above the limits for unrestricted use, as specified in Table 1 of NRC Regulatory Guide 1.86, "Termination of Operating Licenses for Nuclear Reactors." There were no spills or unusual events involving radioactive materials outside of radiologically controlled areas, nor have there been any onsite burials or other onsite disposal of radioactive material.

LIPA submitted its initial decommissioning plan to NRC for review in December 1990, and responded to three rounds of NRC requests for additional information in 1991. A decommissioning order was issued on June 11, 1992, which authorized the licensee to begin decommissioning/decontamination of the facility.

The licensee proceeded with decommissioning of the reactor vessel's internal components, the activated portion of the RPV, and contaminated piping and equipment. These items were segmented as necessary, packaged, and shipped off site for volume reduction or burial (or both) at a licensed low-level waste disposal facility. The fuel was stored in the SFSP during this period.

Radioactive portions of the reactor bioshield wall exceeding the gamma dose rate criterion were also removed and disposed of off site; however, to maintain exposure as low as is reasonably achievable (ALARA) during the disposal of other large sections of this wall, the licensee requested and received NRC's permission, in June 1994, to apply increased surface contamination limits for iron-55 and tritium above those specified in Regulatory Guide 1.86. These revised limits were presented to the Commission in SECY 94-145, and increased the allowable residual average and maximum total residual beta activity levels for iron-55 and tritium from 5000 average total and 15,000 maximum total (fixed plus removable) disintegrations per minute (dpm)/100 square centimeters to 200,000 average total and 600,000 maximum total dpm/100 square centimeters, respectively. This permitted the licensee to retain on site major portions of the wall that did not exceed the gamma dose rate criterion or the surface contamination limits for other isotopes, but which would have required offsite disposal under the original iron-55 and tritium surface contamination limits of Regulatory Guide 1.86. Wall segments cut out from their original locations to enable removal and disposal of the more activated portions of the wall were stored in the radwaste building.

Radiological surveys of the facility have shown that contamination was primarily confined to equipment and structural areas within the reactor and radwaste buildings, with relatively slight contamination found in the turbine building. Radioisotopes in activated components (other than fuel assemblies) were determined to include primarily tritium, carbon-14, iron-55, cobalt-60, nickel-59, nickel-63, manganese-54, europium-152, and trace amounts of other isotopes. Contamination of equipment and structural surfaces was primarily limited to cobalt-60 and iron-55. The plant has had no history of contamination from alpha-emitting nuclides, which was attributed to an absence of leaks from the fuel because of its brief, low-power, operating history.

The residual radioactivity criteria for unrestricted release of the facility were established in the approved decommissioning plan and consistent with the guidelines of Table 1 of NRC Regulatory Guide 1.86 (i.e., 5000 dpm/100 square centimeters average total beta activity; 15,000 dpm/100 square centimeters maximum total beta activity; and 1000 dpm/100 square centimeters removable beta activity). In addition, an average gamma dose rate criterion of 5 μR per hour above background at a distance of 1 meter from accessible surfaces in the facility buildings and outdoor areas was established, with any individual gamma exposure measurement not to exceed 10 μR per hour above background radiation. A concentration limit for cobalt-60 in soil and other bulk materials of 8 pCi (picocuries) per gram was also established.

From September 1993 through May 1994, the licensee shipped (in 33 shipments) all its slightly irradiated nuclear fuel to the Limerick Generating Station for reuse. The disposition of the SNPS fuel enabled the licensee to drain and decontaminate the SFSP and dispose of the fuel racks. This work was completed in August 1994 and marked the completion of the last physical decommissioning activities at the SNPS site.

CONCLUSION:

The staff has completed its review of the Shoreham Decommissioning Project Termination Survey final report. The licensee's final survey report documented the level of residual radioactivity remaining at the facility and affirmed that the residual radioactivity met unrestricted use criteria established by the NRC, and that the site was suitable for release for unrestricted use.

A NRC contractor, ORISE, conducted a series of independent confirmatory surveys during four site visits from February 1993 through November 1994. The results of the ORISE confirmatory survey affirmed the licensee's final survey results. On the basis of the decommissioning activities conducted by the licensee, the NRC staff's review of the licensee's termination survey final report, and the results of NRC confirmatory surveys, the staff concludes that the decommissioning process is complete and the site is suitable to be released for unrestricted use. Accordingly, the staff plans to issue an Order terminating the license and authorizing the release of the site for unrestricted use.

COORDINATION:

The Office of the General Counsel has reviewed this paper and has no legal objections.

James M. Taylor
Executive Director
for Operations

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SECY

EXHIBIT DGB-15

AFFIDAVIT OF JENE N. VANCE

DATED MARCH 29, 1993

March 29, 1993

AFFIDAVIT OF JENE N. VANCE

I, Jene N. Vance, being on oath, depose and say as follows:

1. I am President of Vance & Associates of Ruidoso, New Mexico. I have worked in the area of radioactive waste management for the past 29 years. For past 26 years, I have worked with nuclear power plants to develop processes, design treatment systems, and optimize the performance of existing treatment systems in nuclear plants. Over the last eight years, I have been a major contractor with the Electric Power Research Institute (EPRI) performing a variety of research projects in the low level radioactive waste area. A resume of educational and professional background is attached to this affidavit.

2. In May, 1991, I completed a study entitled, "Estimated Unit Volume Waste Disposal Charge for Seabrook Decommissioning Waste," for EPRI. In that study, I concluded that a charge of $139 per cubic foot in 1991 dollars would be reasonably representative of what is likely to be incurred for the disposal of Seabrook decommissioning wastes. I understand the TLG Engineering, Inc. Incorporated this figure in their study of the overall cost of decommissioning Seabrook Station that was submitted to the New Hampshire Nuclear Decommission Financing Committee (NDFC) in May, 1991.

3. The purpose of this affidavit is to provide an updated estimate for the disposal of Seabrook Station's low level radioactive decommissioning waste.

4. For this update, I surveyed the cost estimates of states and compacts that are planning disposal sites. I found that the projected licensing costs, that is, the costs for all activities leading up to the granting of a construction permit and prior to construction, have risen significantly from that assumed in the 1991 estimate. The licensing costs, however, are still a fraction, about 15%, of the total cost of the disposal facility. For the update, I used a value for licensing costs that was in the middle of the range of those surveyed, and substituted it into the economic model for analysis of the unit volume disposal charge. The resulting estimate for the disposal of Seabrook Station's low level radioactive decommissioning wastes is $160 per cubic foot. The basis for this projected cost is a small-to-moderate sized disposal facility employing the more costly underground vault disposal method. If the future facility had a larger capacity than that assumed for the Seabrook estimate, the cubic foot disposal charge would be lower.

5. This charge includes the cost recovery of the site development and pre-operational costs, the facility operating cost, site closure costs and long-term maintenance costs. The estimated charge also provides for a fair rate of return on the funding source and for the site operating entity. Since Seabrook Station is not scheduled to be decommissioned until the expiration of its licensed life in 2026, the disposal facility used would not be one currently in operation. The access charges, consisting of penalties and surcharges allowed by federal law, that now amount to about $220 at the Barnwell facility would not, therefore, apply to Seabrook wastes. As a point of reference, applying the economic models to the existing disposal facility, such as Barnwell, results in a projected burial charge of $44 per cubic foot which is almost identical to the Barnwell 1992 charge of $43 per cubic foot.

Jene N. Vance
Vance & Associates
President

Jene N. Vance

Date Signed: 3/27/93

State of New Mexico)
) ss.
County of Lincoln)

I, Corinne Gonzales, a Notary Public, hereby certify that on the 27th day of March, 1993, personally appeared before me Jene N. Vance, who being first duly sworn, declared that (s)he is the person who signed the foregoing instrument as President, and that the statements therein are true.

Corinne Gonzales
Notary Public

Commission Expires:
8-10-95

(notarial seal)

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R-943271 JK
Hbg. 5/26/95

THE ENERGY JOURNAL

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IAEE

Volume 12, Special Issue 1991
International Association for Energy Economics

Chapter 9

GREENFIELD DECOMMISSIONING AT SHIPPINGPORT: COST MANAGEMENT AND EXPERIENCE

William Murphie

Although there are many indications that nuclear power plants are likely to stay on site for a period of 60 to 100 years after closure, there are also several reasons to remove the facility from the landscape, such as the desire to use the site for a new power plant or other purpose, safety, and aesthetics. Such removal is underway in several countries including Japan, the United Kingdom, and Germany. In this chapter, William Murphie gives us a unique look at the internal cost management and engineering planning experience acquired during the first U.S. commercial-size plant removal, recently completed at the Shippingport Atomic Power Station near Pittsburgh. The project was especially valuable as it provided a detailed comparison between estimated and actual costs. Some of the more important findings were that (1) detailed advance planning is cost effective, (2) labor costs can result in significant increases in total costs, (3) waste disposal costs can bring about substantial discrepancies between planned and realized costs, and (4) actual costs were within 10 percent of the estimated costs. Although there are several differences between the Shippingport reactor and other power plants, this project afforded the nuclear community an early opportunity to gain insights into many of the contingencies that may occur with full dismantlement.

INTRODUCTION

The 72 MW Shippingport Atomic Power Station first achieved criticality in December 1957. An equally important milestone occurred more than a quarter of a century later. In December 1989, the U.S. Department of Energy (DOE) completed the Shippingport Decommissioning Project, marking the world's first commercial-sized nuclear physical decommissioning work. The plan developed 17 technical activity specifications that could be incorporated into bidding documents.

The decommissioning plan incorporated two DOE objectives: (1) maximizing the use of fixed-price subcontracts, and (2) promoting the accumulation of decommissioning experience over more than one segment of the nuclear industry.

The plan was a comprehensive document that included:

- Technical work scope
- Final environmental impact statement
- Financial estimate and cost baseline
- Rationale for key decisions
- Long lead-time items
- Operations schedules
- Engineering calculations
- Radwaste alternatives
- Radionuclide inventory
- Occupational exposure estimates
- Permitting plan
- Safety analysis report

Concurrent with the decommissioning plan preparation, the DOE required preliminary decommissioning cost estimates for budget and planning purposes. The initial total estimated cost (TEC) was based on preliminary estimates for the various decommissioning operations. The changes in these estimates illustrate how dynamic economic conditions inevitably affect any engineering project.

An early version of the DOE Project Plan for Shippingport (prepared in 1979) identified a TEC of $96 million with a project schedule of approximately four years, assuming immediate dismantlement. A 1982 revision of the project plan identified a $66 million TEC. Two factors accounted for this reduction. First, the station shutdown date was accelerated 27 months, from January 1985 to October 1982. At that time, inflation rates were high and schedule alterations could change project costs significantly. Second, an engineering study determined that there were economic benefits to single unit removal of the reactor pressure vessel (RPV), its internals and the neutron shield tank (NST), as compared with segmentation of those items for removal and subsequent overland truck transportation to the disposal site.[1]

1. In 1986 and 1987, two Congressional Subcommittees conducted hearings on the Shippingport Station Decommissioning Project. See "Decommissioning Nuclear Power Plants: The Shippingport Experience," Hearing before the Subcommittee on Investigations and Oversight and the Subcommittee on Energy and Production, 99th Congress, July 30, 1986; and "Decommissioning of Nuclear Powerplants," Oversight Hearing before Subcommittee on Energy and the Environment, 100th Congress, April 23, 1987.

A still later, 1983, decommissioning plan contained a $79.7 million TEC. This upward adjustment from the 1982 plan reflected (1) detailed engineering studies, as opposed to the previous conceptual design level, and (2) an earlier-than-expected date for site turnover from the former plant operator, but with a caretaker period in which little physical work occurred. The turnover date was shifted from October 1985 to June 1984. Subsequently reduced funding resulted in the station being put into a surveillance and maintenance mode until September of 1985, which raised costs.

Other adjustments were made at the same time to incorporate the final environmental impact statement and to change the financing from capital to line item operating funding. These factors, plus some added work and minor error corrections, resulted in a TEC increase of $18.6 million to $98.3 million. This became the official, final DOE cost estimate at the time of contractor selection and contract award.

PROJECT COST AND SCHEDULE CONTROL SYSTEM

The DOE's Office of Management and Administration, in accordance with departmental project management procedures, established the Shippingport project as a "major project." This action required setting up a Cost and Schedule Control System (C/SCS). DOE decided to establish project management control utilizing a site management contractor. The site management contractor was designated the "Decommissioning Operations Contractor" (DOC) and was responsible for all subcontractors.

DOE made clear to the DOC that the C/SCS would be used for project control and that special attention would be given to changes in the decommissioning plan and any modifications to costs or schedules. Changes to the project cost baseline were permitted, using a formal system of change control procedures. A DOE Contracting Officer was vested with responsibility for final approval of changes to the DOC contract baseline. The project and program offices controlled changes to the overall TEC at different levels. The C/SCS and management control over the project cost baseline were important elements in the successful completion of the project.

The C/SCS applied at Shippingport was a system of reporting variances from cost or schedule baselines. The key reporting factors were derived from cost accruals, schedule tracking, and comparison with the baseline data. For example, the sum of budgeted costs representing work scheduled to be completed in a specific time period was termed Budgeted Cost for Work Scheduled (BCWS). The sum of budgeted costs representing completed work in a time period was termed Budgeted Cost for Work Performed (BCWP). Cost actually incurred in accomplishing the work

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SHIPPINGPORT: OVERALL PROJECT PROGRESS

F. P. Crimi, Manager
Decommissioning Services
General Electric - Nuclear Energy
Shippingport, PA

INTRODUCTION

The Shippingport Atomic Power Station (SAPS) consisted of the Nuclear Steam Supply System and associated radioactive waste processing systems, which were owned by the United States Department of Energy (DOE), and the Balance Of Plant, owned by the Duquesne Light Company. The station is located at Shippingport, Pennsylvania, on seven acres of land leased by DOE from Duquesne Light Company. The Shippingport Station Decommissioning Project (SSDP) is being performed under contract to the DOE by the General Electric Company and its preselected subcontractor, MK-Ferguson Company, as the Decommissioning Operations Contractor (DOC).

Reference (1) reported the status of the SSDP through June 1988. This paper describes the decommissioning work which has been accomplished since July 1988, and the Project's cost and schedule status.

DESCRIPTION OF WORK

A number of major accomplishments were completed successfully in CY 1988. The key event was the preparation for lifting and storing the 900 ton shielded Reactor Pressure Vessel/Neutron Shield Tank (RPV/NST). This work had to be accomplished in parallel with the decontamination and demolition of structures which were on the Project's critical path. The preparations for removal of the RPV/NST included the erection of a lifting tower and hydraulic hoisting trolley, and load testing the tower, the RPV/NST shipping cradle, and the 320 wheel, 20 axle transporter. A barge slip was constructed on the south bank of the Ohio River adjacent to the Shippingport Site and a road was built to connect the barge slip with the lifting tower pad. The details of the lifting tower, road, and barge facility, are documented in Reference (2). The RPV/NST was lifted 77 feet out of its reactor enclosure and downended onto its shipping cradle and transporter on December 14, 1988. The loaded transporter was moved to its temporary storage pad on December 15, 1988.

A major work effort during most of 1988 was the decontamination and demolition of the Fuel Handling Building, the Fuel Storage Canal, and the Radioactive Waste Processing Building and Yard. A total of 41 truck shipments of Low Specific Activity (LSA) solid waste material were made to DOE's Hanford, Washington burial grounds along with 4 radioactive mixed waste and 6 hazardous waste truck shipments. The processing of all radioactive water was completed in September 1988, bringing the total quantity of water processed during the project to 576,400 gallons. Another large work effort involved the conduct of radiation surveys and the preparation of documentation packages to support the release of areas concurrent with the demolition process. This work is described in Reference (3).

In February 1989, the "Paul Bunyon", a 4,000 ton ocean barge, arrived at the Shippingport barge slip. The RPV/NST package, which had been secured to its shipping cradle was fastened to the transporter and placed on the barge along with one 700 horsepower prime mover and a set of bridging mats. Seafasteners were positioned and welded to the barge deck to securely hold the RPV/NST, shipping cradle and transporter, the prime mover, and bridging mats during the 7,000 nautical miles water voyage to Hanford, Washington. Additional details of the RPV/NST shipment can be found in Reference (4). In April, 1988, the RPV/NST package was unloaded from its transporter in a burial trench in the 200 West Area of DOE's Hanford, Washington site.

The demolition and release of all remaining structures by GE was completed in May 1989, followed by the backfilling of the Auxiliary Containment Chamber Enclosure. The final grading and seeding of the Shippingport Site and final site release radiation surveys by General Electric will be completed in the summer of 1989. An overcheck radiation survey of all site areas will be performed for DOE by their Independent Verification Contractor. These surveys will demonstrate that the Shippingport Site can be released back to Duquesne Light Company for unrestricted use.

RESULTS

The total cost of the SSDP is estimated to be less than the $98.3M budgeted for the Project. General Electric plans to submit its technology transfer reports to DOE before the end of CY 1989 and DOE's Final Report is scheduled for completion in April 1990.

As the first decommissioning of a commercial, full scale nuclear power plant, the Shippingport Station Decommissioning Project is expected to set the standards for the demolition of future nuclear power plants.

REFERENCES

(1) Crimi, F. P., "Physical Decommissioning of the Shippingport Atomic Power Station", presented at the American Nuclear Society (ANS) Spectrum 88 Conference, Pasco, Washington, September 11-15, 1988

(2) Yannitell, D. M., "RPV/NST: Preparation, Lifting and Loading", presented at the 1989 American Nuclear Society (ANS) Annual Meeting, Atlanta, Georgia, June 4-8, 1989

(3) Eger, K. J., "Progress on Release of Shippingport Site and Materials", presented at the 1989 American Nuclear Society (ANS) Annual Meeting, Atlanta, George, June 4-8, 1989

(4) Coughlin, P. J. "RPV/NST: Shipment and Burial", presented at the 1989 American Nuclear Society (ANS) Annual Meeting, Atlanta, George, June 4-8, 1989

ANS Annual Meeting
Atlanta, Georgia
June 1989

SHIPPINGPORT: OVERALL PROJECT PROGRESS

F.P. Crimi

GE Nuclear Energy

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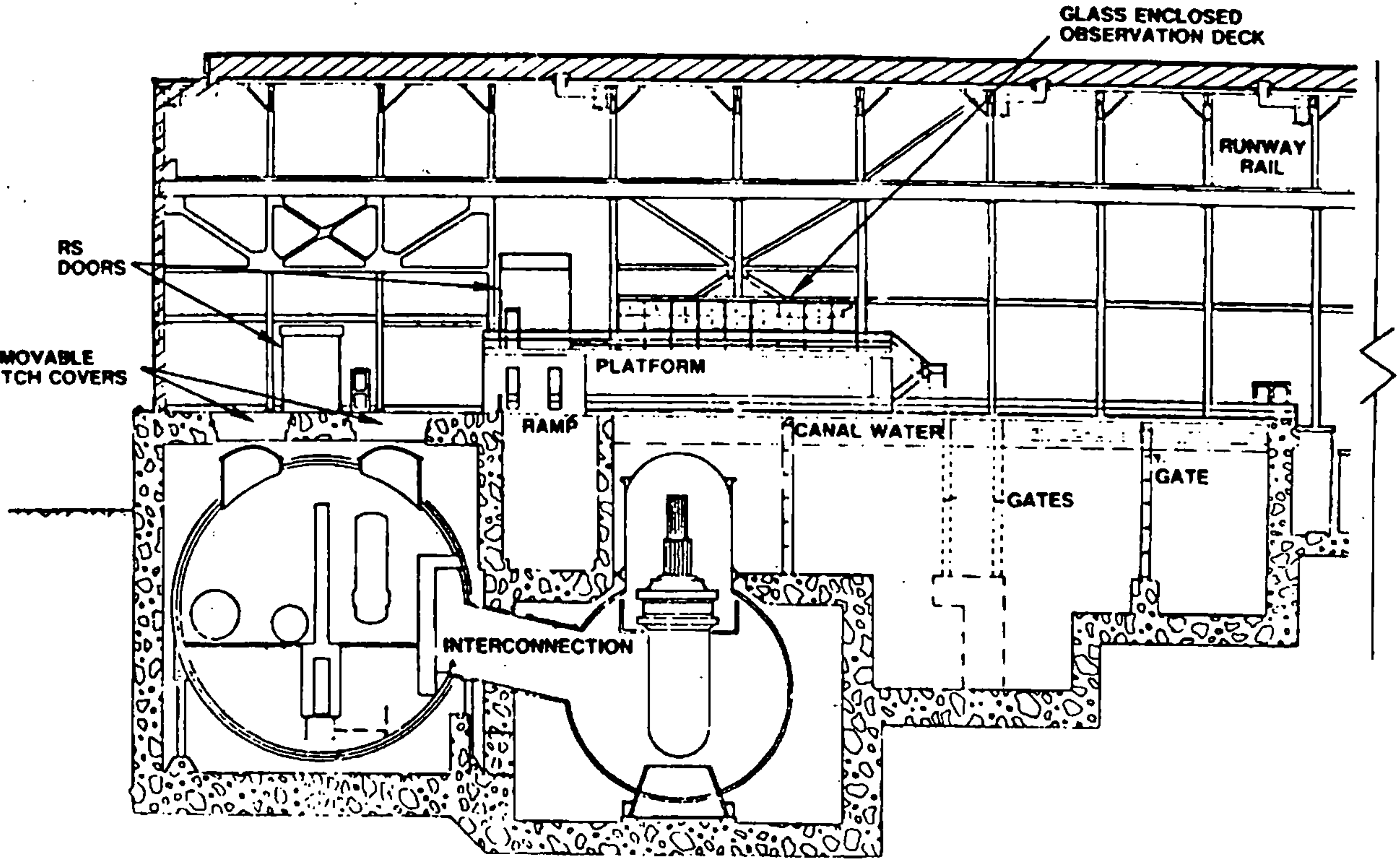
SHIPPINGPORT STATION DECOMMISSIONING PROJECT

SHIPPINGPORT ATOMIC POWER STATION



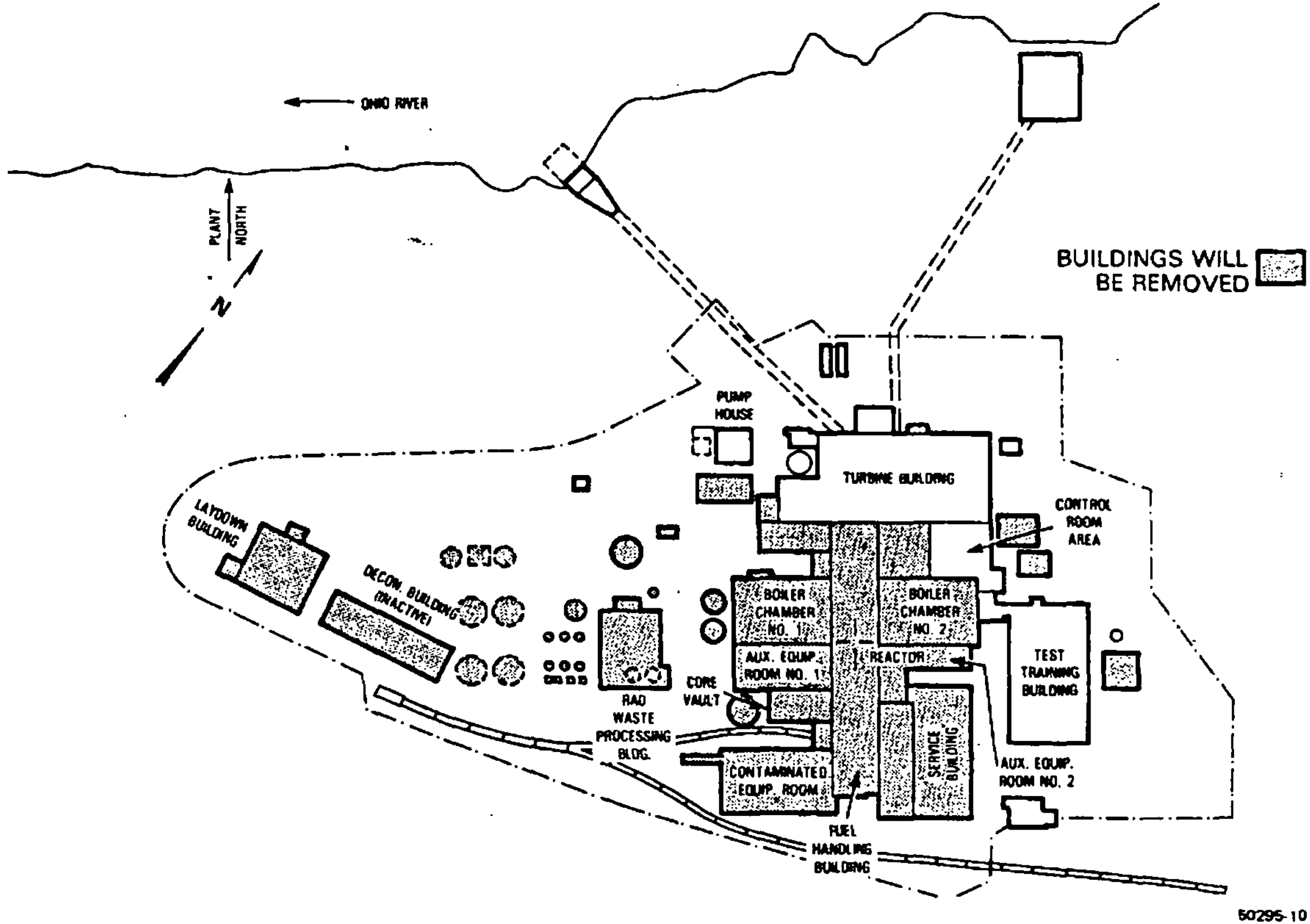
SHIPPINGPORT STATION DECOMMISSIONING PROJECT

WHY SHIPPINGPORT?

- **Demonstrate Safe and Cost-Effective Dismantlement of Large Scale Nuclear Power Plant**
- **Provide Know-How and Industry Standards for Future Projects**

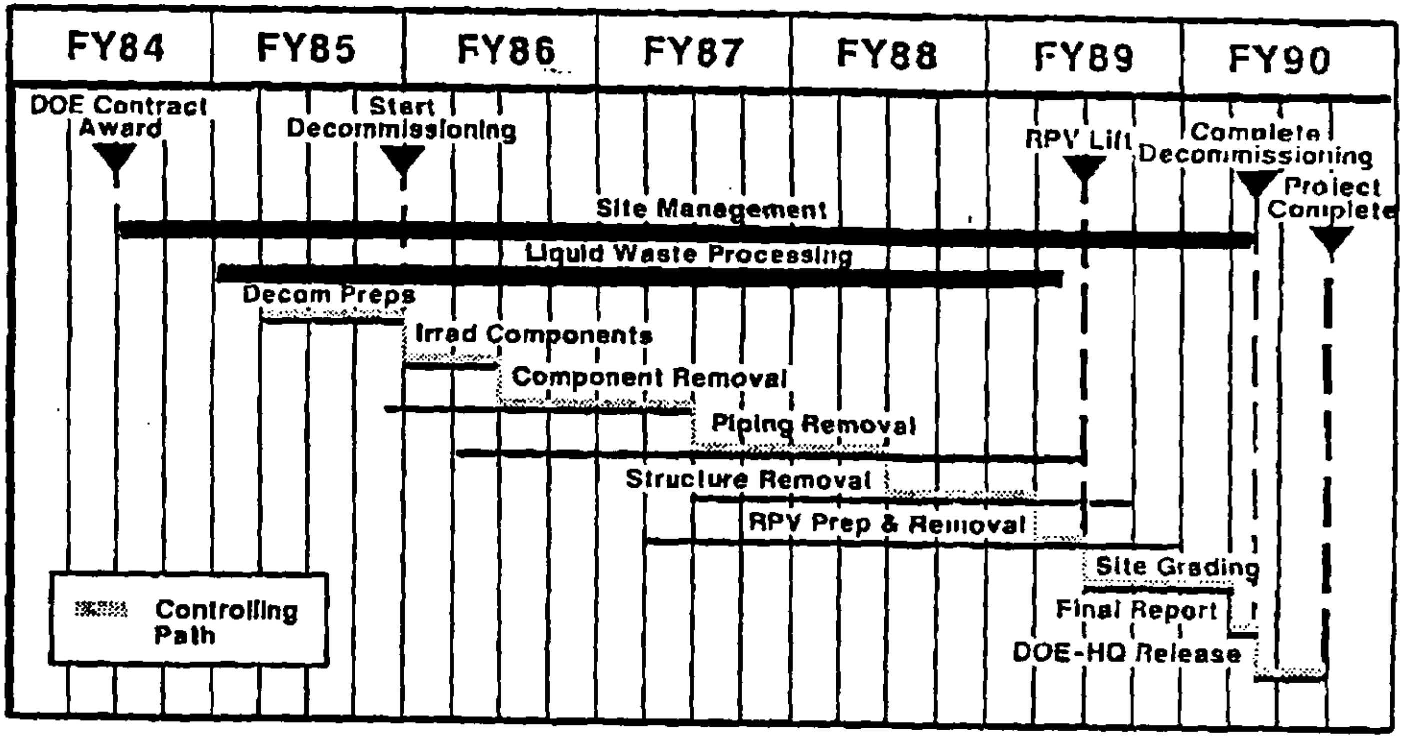
SHIPPINGPORT STATION DECOMMISSIONING PROJECT

SHIPPINGPORT STATION SITE PLAN



SHIPPINGPORT STATION DECOMMISSIONING PROJECT

DOC SCHEDULE



SHIPPINGPORT STATION DECOMMISSIONING PROJECT

PROJECT COST BREAKDOWN

Engineering (BRISC)	$ 6.0M
Technical Management Support (UNC)	7.3M
Station Operator Support (DLC)	1.0M
Site Management & Support (GE/MK)	35.9M
Decommissioning Activities (GE/MK)	36.5M
Subtotal	$ 86.7M
Contingency	11.6M
Total	$ 98.3M

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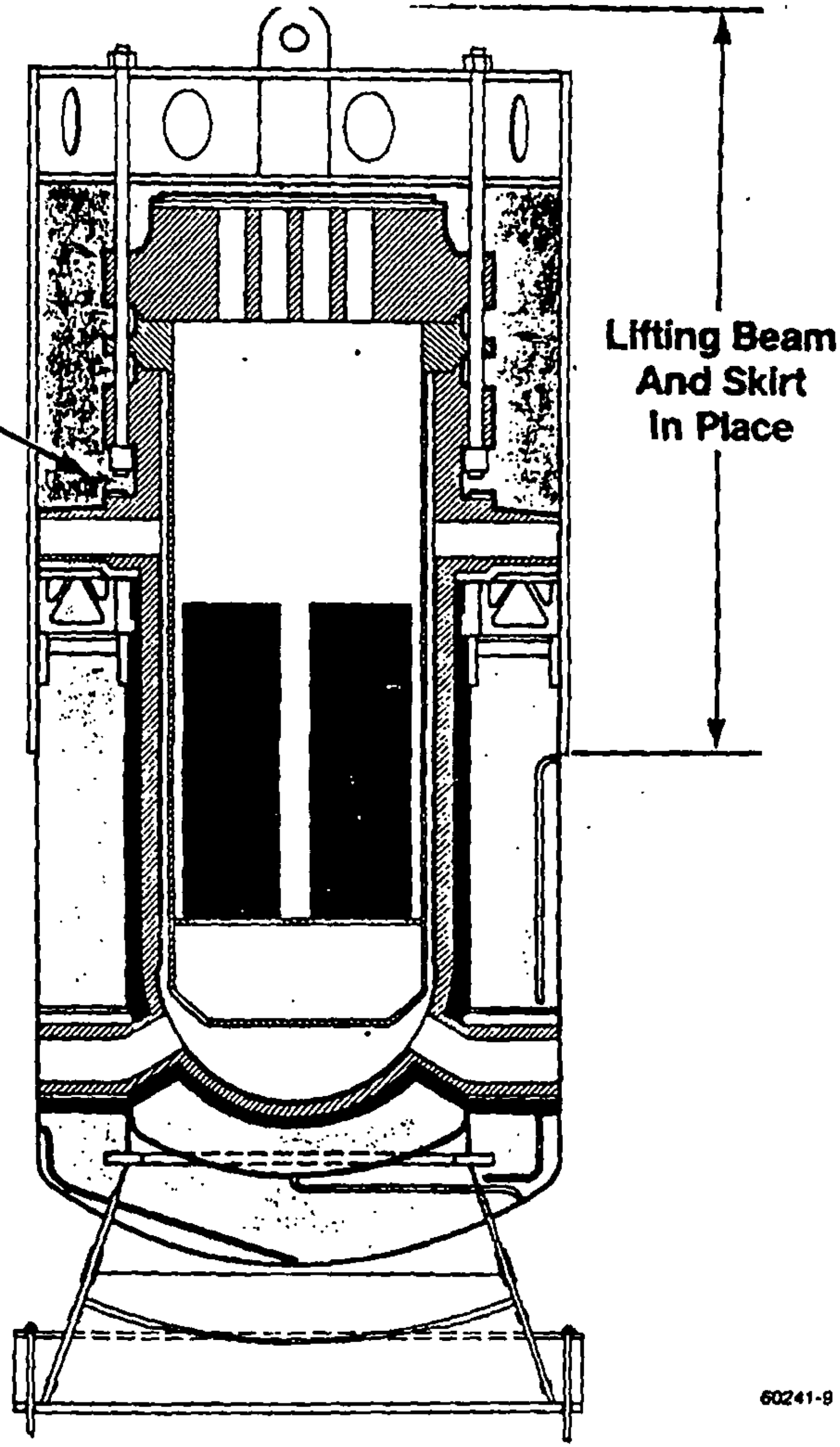
Shippingport RPV/NST Transportation Package

Plate IX

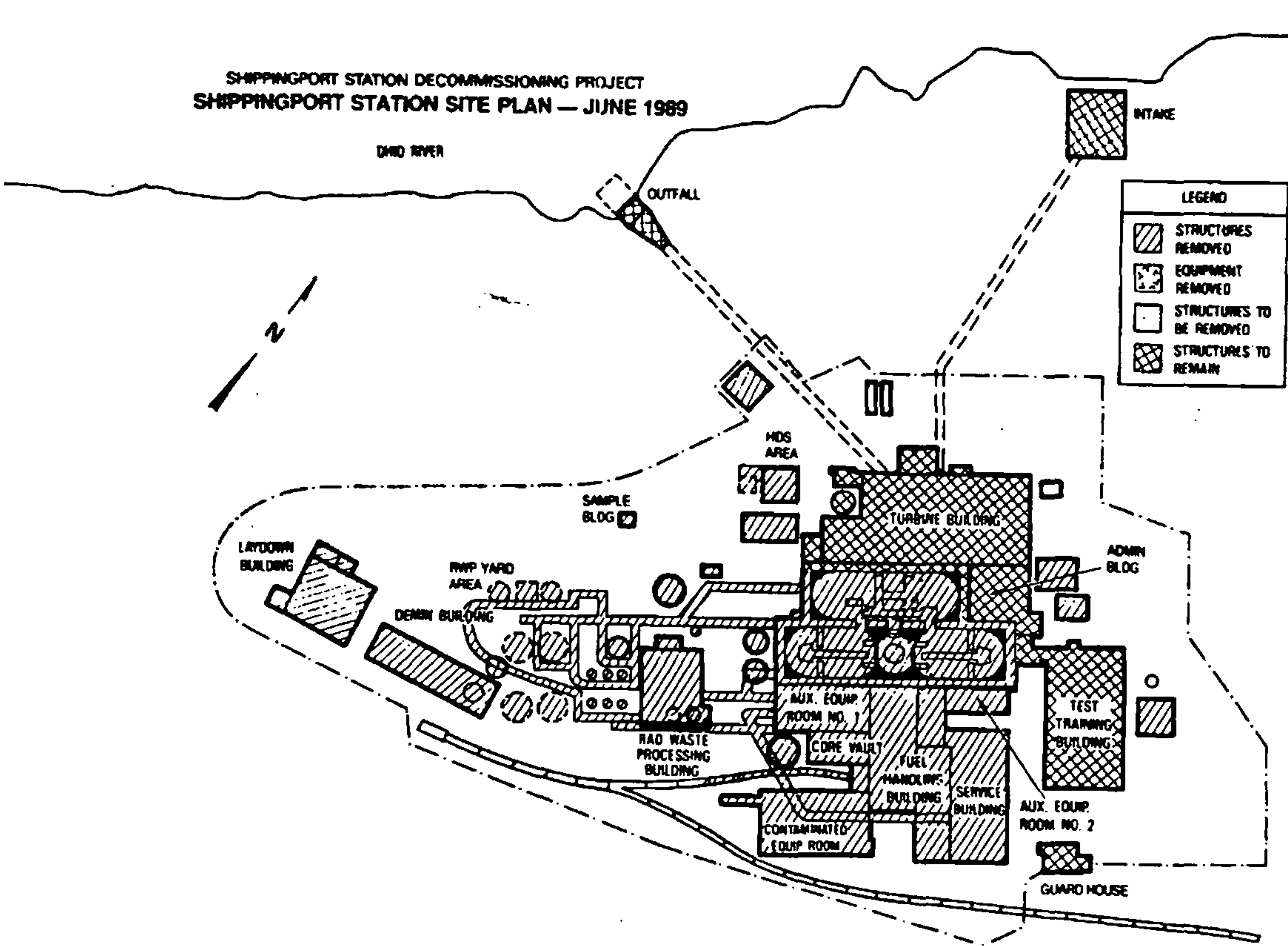
Install Concrete Inside Lifting Skirt And Beam



SHIPPINGPORT STATION
DECOMMISSIONING
PROJECT

BARGE TRANSPORTATION ROUTE

SHIPPINGPORT STATION DECOMMISSIONING PROJECT
SHIPPINGPORT STATION SITE PLAN — JUNE 1989



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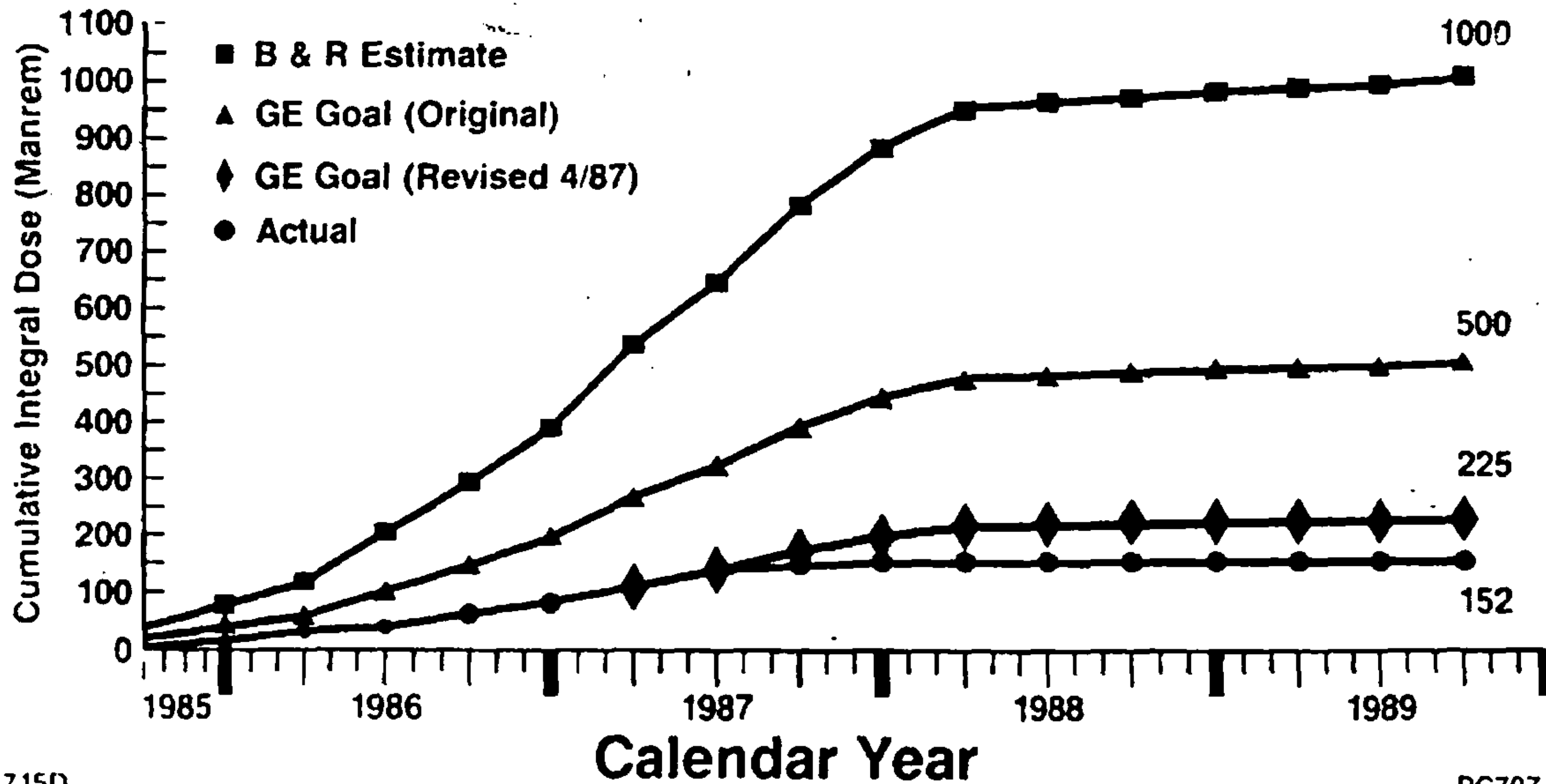
SHIPPINGPORT STATION DECOMMISSIONING PROJECT
CUMULATIVE PERSONNEL EXPOSURE DECOMMISSIONING PHASE



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SHIPPINGPORT STATION DECOMMISSIONING PROJECT

VISITORS TO A HIGH VISIBILITY PROJECT

USA

- Federal Government
  - Congressmen
  - NRC/EPA/DOE
- State Government
  - PA/IL
- Local/County
  - PA/OH/WV
- 22 Utilities
- National Labs
- Electric Utility Groups

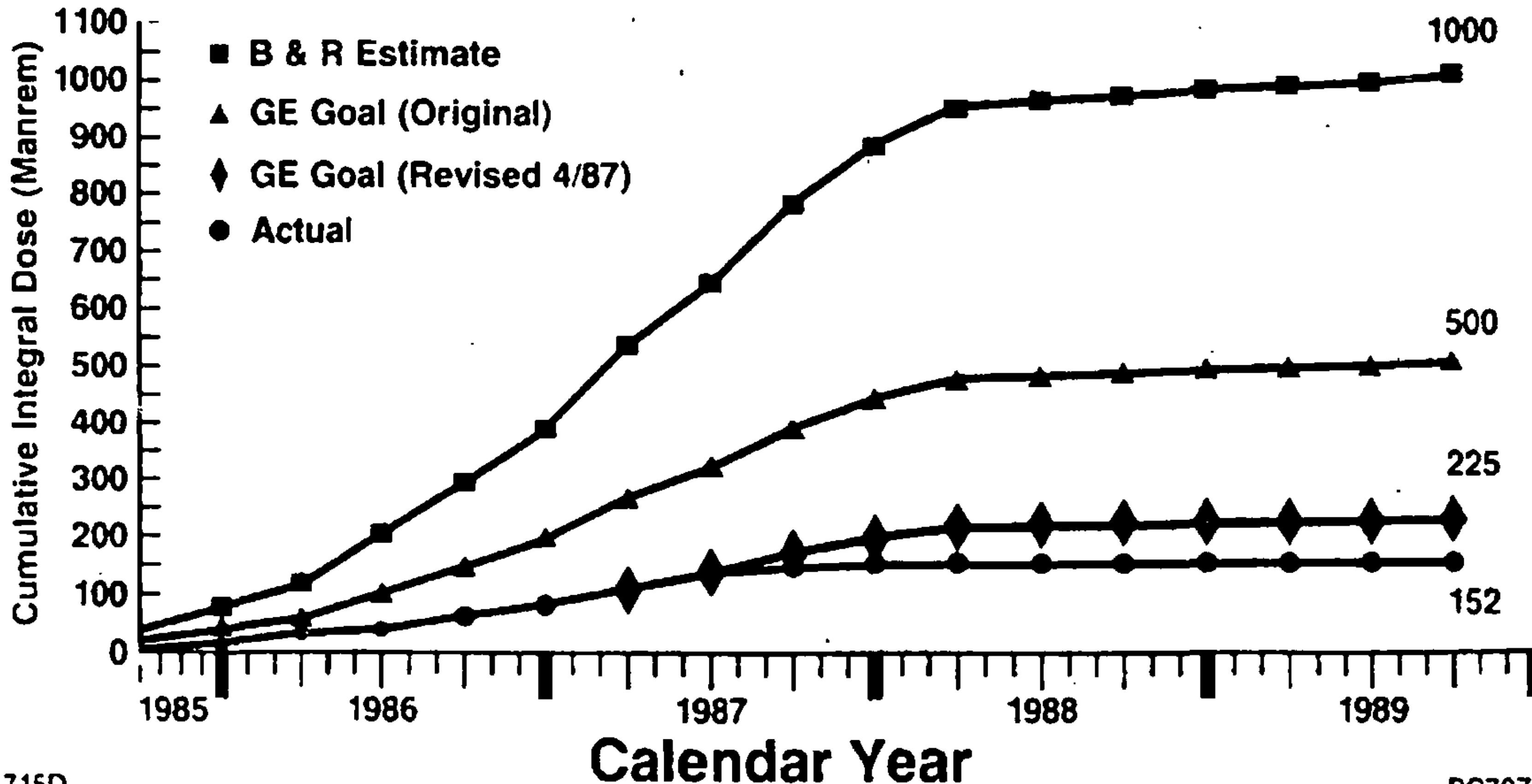
International

- Japan - 6 Assignees
  - 14 Utilities
  - Construction Co.'s
- Korea - 2 Assignees
- Taiwan - 1 Assignee
- Australia
- FR Germany/Sweden
- France/Italy
- UK/Canada

Media

- Newspapers
  - U.S. National
  - Japan/Sweden
- TV - Radio
  - CBS/NBC/CNN/VOA
  - Japan/Italy
- Magazines
  - BusinessWeek
  - Forbes
  - Newsweek
  - Nat. Geographic

SHIPPINGPORT STATION DECOMMISSIONING PROJECT
CUMULATIVE PERSONNEL EXPOSURE DECOMMISSIONING PHASE



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PA PUBLIC UTILITY COMMISSION
V. PENNSYLVANIA POWER & LIGHT
COMPANY
DOCKET NO. R-00943271

OCA CROSS EXAMINATION EXH.NO. 22

DATE ENTERED: 5/26/95

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Pennsylvania Power & Light Company
Response to Interrogatories of
the Office of Consumer Advocate, Set XVI
Dated May 10, 1995

Docket No. R-00943271

Q.11. Given the load forecast and capacity resources shown in Mr. Sipics' direct testimony, when (i.e., in what year) does Dr. Hieronymus believe that PP&L should be adding new capacity in order to meet reliability needs? Please explain the basis for his opinion.

A.11. Dr. Hieronymus did not analyze when PP&L should be adding new capacity in order to meet reliability needs.

Pennsylvania Power & Light Company
Response to Interrogatories of
the Office of Consumer Advocate, Set XVI
Dated May 10, 1995

Docket No. R-00943271

Q.12. Setting ratemaking aside, what planning reserve margin target does Dr. Hieronymus believe PP&L system within the next ten years would be consistent with a least-cost resource plan? If so, please explain the basis for his opinion.

A.12. Dr. Hieronymus' analysis did not address what planning reserve margin target would be consistent with a least-cost resource plan for PP&L over the next ten years.

Pennsylvania Power & Light Company
Response to Interrogatories of
the Office of Consumer Advocate, Set XVI
Dated May 10, 1995

Docket No. R-00943271

Q.13. Has Dr. Hieronymus conducted any studies concerning whether adding a coal unit to the PP&L system within the next ten years would be consistent with a least-cost resource plan? If so, please supply any such study.

A.13. Dr. Hieronymus did not conduct any studies concerning whether adding a coal unit to the PP&L system within the next ten years would be consistent with a least-cost resource plan.

Pennsylvania Power & Light Company
Response to Interrogatories of
the Office of Consumer Advocate, Set XVI
Dated May 10, 1995

Docket No. R-00943271

Q.14. If Dr. Hieronymus has not conducted such a study, does he have an opinion on whether a new coal plant would be a cost-effective addition to PP&L within the next ten years? Please explain any such opinion.

A.14. Dr. Hieronymus is unable to offer such an opinion since he has not performed the necessary supporting analyses.

Pennsylvania Power & Light Company
Response to Interrogatories of
the Office of Consumer Advocate, Set XVI
Dated May 10, 1995

Docket No. R-00943271

Q.15. Has Dr. Hieronymus conducted any studies or analyses concerning whether adding a coal plant would be part of a least-cost plan for PP&L within the next ten years, assuming removal from service of a Susquehanna nuclear unit (or portion thereof)? If so, please supply any such studies or analyses. If not, please identify any opinion Dr. Hieronymous has on this issue.

A.15. Dr. Hieronymus has not conducted any studies or analyses concerning whether adding a coal plant would be part of a least-cost plan for PP&L within the next ten years, assuming removal from service of a Susquehanna nuclear unit (or portion thereof).

Pennsylvania Power & Light Company
Response to Interrogatories of
the Office of Consumer Advocate, Set XVI
Dated May 10, 1995

Docket No. R-00943271

Q.17. Please identify any disagreements that Dr. Hieronymus has with PP&L's 1995 ARPR. If he has not reviewed or examined that report, please so indicate. If he has examined the 1994 ARPR but not the 1995 ARPR, please indicate any disagreements with the 1994 ARPR.

A.17. Dr. Hieronymus has not reviewed PP&L's 1995 ARPR, nor has he examined the 1994 ARPR.

Pennsylvania Power & Light Company
Response to Interrogatories of
the Office of Consumer Advocate, Set XVI
Dated May 10, 1995

Docket No. R-00943271

Q.19. Dr. Hieronymus discusses market prices for baseload power at page 51 of his rebuttal testimony. Does he have any information concerning current market prices in wholesale markets for baseload type power over the next five to ten years in the PJM region? This question refers to either recently established transactions or current projections. If so, please supply this information, including such information on market prices given to Dr. Hieronymus by PP&L.

A.19. Dr. Hieronymus did not perform a specific analysis of the wholesale electric market in the PJM region. Dr. Hieronymus is generally aware, however, of certain projections made by the Company, which have been previously provided to other parties in the discovery process of this case.

PA PUBLIC UTILITY COMMISSION
V. PENNSYLVANIA POWER & LIGHT COMPANY
DOCKET NO. R-00943271

OCA CROSS EXAMINATION EXH.NO. 23

DATE ENTERED: 5/26/95

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Response to Interrogatories of
the Office of Consumer Advocate, Set XVI
Dated May 10, 1995

Docket No. R-00943271

Q.24. Please provide Dr. Hieronymus' estimate of the annual base and fuel revenue requirements for Susquehanna Unit 2 each year of his study period. Do these costs reflect any of the savings or improvements recommendations in the Strategy 2000 study? If so, please identify which ones and how much savings is assumed to result.

A.24. Dr. Hieronymus estimates the capital charge revenue requirement for Susquehanna Unit 2 for 1995-2004 to be as follows (dollars in millions):

1995	$259.586
1996	$276.497
1997	$274.442
1998	$273.323
1999	$217.603
2000	$218.222
2001	$228.525
2002	$223.439
2003	$218.416
2004	$213.442

Dr. Hieronymus estimates the fuel cost revenue requirement for Susquehanna unit 2 for 1995-2004 to be as follows (dollars in millions):

1995	$22.948
1996	$26.551
1997	$23.062
1998	$23.952
1999	$30.435
2000	$27.678
2001	$30.227
2002	$36.734
2003	$31.807
2004	$32.268

These costs do not reflect any of the recommendations in the Strategy 2000 study.

OTS Statement No. SR5
Dated: ~~April 19, 1995~~
May 18, 1995
Hbg JK R-943271
5/26/95

DOCUMENT
FOLDER

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PENNSYLVANIA POWER & LIGHT COMPANY

Docket No. R-00943271

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INFO. CONTROL DIV.

DOCKETED
JUN 01 1995

Surrebuttal Testimony

of

Paul J. Metro

Office of Trial Staff

Concerning:

Excess Capacity

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Paul J. Metro. My business address is P.O. Box 3265, Harrisburg, Pennsylvania 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission in the Office of Trial Staff as a Fixed Utility Valuation Engineer working in the Rate Structure/Engineering Section of the Energy Division.

Q. DID YOU PRESENT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes I did. I was responsible for OTS Statement No. 5.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to respond to PP&L witness Dr. Hieronymus concerning his rebuttal statement that the calculation of my forced outage factor contains a major conceptual error. (See PP&L Statement 16R, page 6, lines 3-9).

Q. MR. METRO, WHAT IS THE PURPOSE OF YOUR FORCED OUTAGE FACTOR?

A. My forced outage factor is intended to be a "contingency" or "padding" factor. I do not believe in a strict calculation of an allowed reserve and, therefore, included an additional contingency factor to recognize the fact that additional resources may be needed during peak periods due to unforeseen factors, such as, frozen coal piles or greater than expected demand. In order to be <u>conservative</u> in my excess capacity adjustment, I included a factor which, when applied to the available resources, would reduce the available resources at the time of peak. This factor was used to increase the reserves at the time of peak above the 12% PJM minimum requirement. By using my forced outage factor, I increased the reserve margin from 12% (which already included a forced outage amount) to approximately 16% over the resources needed at the time of peak.

Q. HOW DID YOU QUANTIFY THE FORCED OUTAGE FACTOR?

A. The factor was calculated by taking the estimated lost generation due to forced outages per year and dividing that amount by 8,760 hours per year. The factor for the 1995/1996 winter period was calculated to be 250 MW per year. I then increased the factor each year in relationship to an increase in the net resources. My calculation was not intended to reflect the total forced outages that could occur at peak period.

Q. WOULD YOU EXPLAIN YOUR INTENTIONS CONCERNING THE 250 MW PER YEAR FORCED OUTAGE FACTOR UTILIZED IN YOUR RESERVE MARGIN CALCULATIONS?

A. Yes I will. The intent of the 250 MW per year forced outage factor was to create a factor that was not duplicative of the forced outage already included in the 12% PJM minimum reserve requirement. The intent was to provide a conservative supplemental forced outage factor over and above the 9.7% forced outage amount included within the 12% PJM reserve requirement. The forced outage factor was not intended to represent actual forced outages during the peak, but was intended to supplement (or inflate) the peak period forced outages already included within the 12% PJM reserve margin calculation. As I have previously stated, my forced outage factor was intended to be a contingency factor.

Q. MR. METRO, WHEN YOU DERIVED THE FORCED OUTAGE FACTOR, DID YOU TAKE INTO CONSIDERATION THAT THE 12% PJM MINIMUM RESERVE REQUIREMENT ALREADY INCLUDED A FORCED OUTAGE FACTOR?

A. Yes I did. Mr. Sipics acknowledged that the 12% PJM reserve requirement included a forced outage rate of 9.7% during cross examination of his direct testimony. (See Tr. page 327, lines 9-23) In fact, Mr. Sipics quantified the forced outage megawatts, which were included in the 12% PJM reserve requirement, to be 875 MW.

Q. DO YOU AGREE WITH DR. HIERONYMUS' REBUTTAL TESTIMONY ON PAGE 27, LINES 18-22?

A. No I do not. Dr. Hieronymus has erred in his review of OTS Exhibit No. 5, Schedule 3. Schedule 3 shows the derivation of the forced outage factor. Dr. Hieronymus erred in his description of the derivation of the 250 MW per year calculation. He states that the generation due to forced outages was divided by 8760 hours to derive an hourly average generation lost because of forced outages. This is not correct. The generation due to forced outages was divided by 8760 <u>hours/year</u> to derive a megawatt per year amount.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes it does.

NOT LISTED

PUC LATE-FILED EXHIBITS

KJR

Docket No. R-943271

Hearing Date 5-26-95

Judge Christianson

Hearing held in Harrisburg, PA

Exhibit No. PP+L Cross-Exam Exhibit #1

Reporter John A. Kelly

1. Above exhibit to be supplied to reporter by:

DOCUMENT FOLDER

2. Above exhibit to be filed directly with PUC by:

Additional Comments:

Please add to exhibit file per attached letter.

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THOMAS P. GADSDEN
DIAL DIRECT (215) 963-5234

June 7, 1995

BY FIRST CLASS MAIL

Honorable Robert A. Christianson
Acting Chief Administrative Law Judge
Pennsylvania Public Utility Commission
North Office Building, Room G-06
P. O. Box 3265
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission
v.
Pennsylvania Power & Light Company
Docket No. R-00943271

Dear Chief Judge Christianson:

At the hearing held on May 26, 1995, I cross-examined Office of Consumer Advocate witness Kahal regarding testimony that he had presented in a previous proceeding captioned Petition of Bethlehem Steel Corporation and Hadson Development Corporation at Docket No. P-870235. As you may recall, my questions went to certain avoided cost calculations that he had performed in that case and, more specifically, to the derivation of a levelized figure of approximately 8.5¢ per kilowatthour.

As reflected at transcript pages 2378-2379, I later asked a data request directed to that particular testimony. At that point, it was suggested that such testimony may already have been provided to Pennsylvania Power & Light Company ("PP&L") as part of the discovery process. Upon further review of our records, I have determined that, in lieu of furnishing copies of prior testimony, Mr. Kahal made such testimony available for review at his office in Maryland. And, while one of our consultants did visit Mr. Kahal's office, no testimony was reproduced at that time.

I have since obtained a copy of Mr. Kahal's testimony and supporting schedules from the Bethlehem Steel case and believe that the portions of that material dealing with his avoided cost calculations should be admitted as a late-filed exhibit to clarify the record in this proceeding. I have therefore enclosed two copies of what has been pre-marked as PP&L Cross-Examination Exhibit 1, consisting of the cover page, pages 53-59 and Schedules MIK-5 and MIK-7 from Mr. Kahal's direct testimony in Bethlehem Steel, and request that it be accepted into evidence as marked.

As noted below and on the attached Certificate of Service, I am concurrently providing copies of PP&L Cross-Examination Exhibit No. 1 to the Court Reporter and to all active parties of record.

Sincerely,

Thomas P. Gadsden

Thomas P. Gadsden
Counsel for Pennsylvania
Power & Light Company

TPG:jod
Enclosure

cc: Commonwealth Reporting Service
All Active Parties of Record

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	
v.	:	DOCKET NO. R-00943271
PENNSYLVANIA POWER & LIGHT COMPANY	:	

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document upon the participants listed below, in accordance with the requirements of Section 1.54 (relating to service by a participant).

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Dated: June 9, 1995

Thomas P. Gadsden

Thomas P. Gadsden
Counsel for Pennsylvania Power
& Light Company

PP&L CROSS-EXAMINATION EXHIBIT NO. 1

R-943271
5-26-95
JAK
Hbg

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PUBLIC UTILITY COMMISSION

Amended Petition of Bethlehem Steel Corporation and Hadson Development Corporation	)	Docket Nos. P-870235
American Power Corporation and CMS Generation Company v. Pennsylvania Electric Company	)	C-913318
Petition of Cambria Partners	)	P-910515
Robert Robinson v. Pennsylvania Electric Company	)	C-913764

DOCKETED
JUN 23 1995

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INFO. CONTROL DIV.

DIRECT TESTIMONY

OF

MATTHEW I. KAHAL

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

MARCH 1992

EXETER
Associates, Inc.

10801 Lockwood Drive
Suite 350
Silver Spring, MD 20901

I have accepted the Penelec combined cycle costs, although there is evidence they are overstated.

The changes I have identified are projections and therefore uncertain. No one can know how much natural gas will cost over the next 30 years or the actual cost of constructing a coal plant in the late 1990s. Nonetheless, I believe the changes that I have made to Penelec's planning assumptions are conservative and are essential to protect ratepayers from paying excessive costs associated with QF contracts. The assumptions embedded in the avoided cost calculations of Drs. Shanker and Venkateshwara expose ratepayers to unreasonable risk.

Avoided Cost/Contract Cost-Effectiveness

Q. HOW HAVE YOU CONDUCTED YOUR AVOIDED COST ANALYSIS?

A. I have performed two separate studies. The first is the standard GPU differential revenue requirements analysis using Dr. Shanker's Case 1 (i.e., replace 80 mW of combined cycle capacity in 1997 with 80 mW of QF purchases). I made only one change to his Case 1 study, my revised fuel price projections. In my opinion, this study produces valid, though conservatively high estimates of avoided cost for an 80 mW QF.

The second study is a traditional coal proxy analysis. I have performed this study as a check on the coal proxy study submitted by Dr. Venkateshwara. The coal proxy study approach is of highly questionable validity, since Penelec has no plans to add coal capacity until 2005. I therefore regard my coal proxy study as illustrative.

In addition to these two studies, I comment briefly on Dr. Venkateshwara's "Ratepayer Acceptability Test" and PURPA energy rate comparison.

Q. PLEASE DESCRIBE YOUR DRR ANALYSIS?

A. As stated, my DRR uses GPU's standard methodology and Dr. Shanker's Case 1, along with my fuel price scenario ($2.50 per MMBtu in 1992 for natural gas and 8 percent escalation). This analysis was conducted by GPU staff using the PROBSYM model at the request of the OCA.

The computer output results are summarized on page 1 of Schedule MIK-4. The energy portion of avoided cost is shown for the on-peak period, off-peak period and an "all hours" weighted average and is expressed in dollars per mWh. The final column presents the avoided capacity costs in dollars per mW of capacity. Page 2 of Schedule MIK-1 combines the $/mWh energy and $/mW capacity to produce a rolled-in $/mWh schedule which reflects both capacity and energy. For comparability purposes, I have extrapolated the costs from 2022 when the PROBSYM results end to 2026. The 30-year present value total for 1 mWh per year at a 10.71 percent discount rate is $833.85.

Q. HOW DO YOUR DRR RESULTS COMPARE TO THE THREE CONTRACT OFFERS?

A. I have shown this comparison on Schedule MIK-5. Page 1 of that schedule is based upon a 10.71 percent discount rate, while page 2 is based upon 9.13 percent discount rate. As I mentioned earlier, the American/CMS cost figures are overstated by one year of inflation (i.e., 4 percent) because their offer calls for a 1998, not 1997 in-service date.

These schedules demonstrate that the offers substantially exceed the DRR avoided cost estimates. At a 10.71 percent discount rate, the QF offers are approximately $100 to $106 per mWh levelized compared to levelized avoided costs of $84.67 per mWh. The overstatement is about

20 percent. The results on page 2 using the 9.13 percent discount rate are similar in percentage terms.

Accepting the Commission's order, the DRR results provide a proper evaluation of the LG&E contract since LG&E has been awarded "first in line" status. This analysis overstates the cost-effectiveness of Cambria and American/CMS because it assumes that all 500 mW of capacity from those projects should receive a capacity credit in 1997 (or 1998) when the projects enter service.

Q. HOW HAVE YOU CONDUCTED YOUR COAL PROXY ANALYSIS?

A. That analysis is shown in spread sheet form on Schedule MIK-6. I have begun with the assumption that a coal plant would cost $1,500 per kW in 1990 dollars, or $1,974 for a 1997 in-service. I convert that installed cost to annual capital revenue requirement using the schedule of fixed charge rates in Penelec's 1991 ARPR. However, I have added 0.7 percent each year to the fixed charge rate (about a 5 percent increase) to recognize realty taxes and insurance. The annual capital charges per kW are converted to $ per mWh by dividing 7,008 hours (an 80 percent capacity factor).

The energy component of the coal proxy includes both fuel cost and non-fuel O&M (variable and fixed) per mWh. My energy figures are taken from Penelec's 1991 ARPR, but using 5 percent escalation for coal prices and 4 percent for O&M.

The capacity cost per mWh plus the energy cost per mWh equal the coal proxy total avoided cost. The final column of that schedule converts the total cost per mWh to present values and sums over 30 years.

Q. HOW DOES THIS COMPARE TO THE THREE OFFERS?

A. The comparison is shown on Schedule MIK-7, with page 1 using a 10.71 percent discount rate and page 2 using the 9.13 percent figure. The levelized cost of the coal proxy is about $90 per mWh, compared to about $85 for the DRR, confirming that Penelec's choice of a combined cycle over a coal plant in 1997 is an economic choice. While the coal proxy comparison is more favorable than the DRR to the cogenerator contract offers, it is still much less costly than those offers. The cogenerator offers are about 10 to 15 percent above the coal proxy.

Q. IS THE COAL PROXY COMPARISON APPROPRIATE?

A. No, it has several shortcomings. First, as was just mentioned, a coal plant in 1997 is less economic than the combined cycle. Avoided cost should reflect, to the extent practicable, a utility's least-cost (or most appropriate) resource options. Second, the American/CMS and Cambria capacity is largely excess capacity in the early years. This analysis assumes that 580 mW of coal capacity is needed in 1997/1998.

The third concern is referred to as an "end effects" problem and is very subtle. The problem arises because the cogeneration contract and the utility generation resource it replaces have differing lives. The contracts have assumed lives of 25 to 30 years, but the coal plant probably has a useful life of 40 to 50 years (or more). This means that at the end of the 25 year contract, Penelec must secure a new resource based on market prices or replacement costs at that time. For example, if a coal plant costs $2,000 per kW in 1997, the replacement coal plant will cost about $5,500 per kW in 2021 when the QF contract expires. On the other hand, had Penelec not accepted the QF contract, in 2021 it would have a mostly depreciated but still very serviceable coal plant which can provide cheap coal energy for its customers for another two or three decades. As a technical matter, the coal proxy rates should be adjusted downward to take end effects into account.

For all three reasons, I believe my coal proxy study on Schedule MIK-6 is biased in favor of the cogenerators.

Q. DR. VENKATESHWARA OBTAINED MUCH HIGHER COSTS FROM HIS COAL PROXY ANALYSIS. HOW DO YOU EXPLAIN THAT?

A. There appear to be two main differences between our two studies. First, he assumes a Penelec coal plant costing $2,700 per kW. I believe that is an unrealistically and unreasonably expensive coal plant. Second, he assumes realty taxes and insurance -- two very minor expense items -- add nearly 20 percent of the carrying charge rate. This is equivalent to increasing the cost of the coal plant from $2,700 to $3,200 per kW. While I agree that these items should be included, they are just not that expensive.

Q. DR. VENKATESHWARA SHOWS SAVINGS FOR THE CAMBRIA CONTRACT USING HIS "RATEPAYER ACCEPTABILITY TEST". IS THAT A REASONABLE ANALYSIS?

A. This study assumes that Cambria replaces 200 mW of Met Ed and Penelec capacity in the late 1990s. Aside from the controversy of using Cambria to meet Met Ed's need, there are biases on both the capacity and energy side of his analysis. On the capacity side, he takes Penelec's already high combined cycle cost of $723 per kW and increases it by another $100 (about 15 percent). Next, he adjusts the fixed charge rate, as before, for his very large realty taxes and insurance adder. These adjustments lead to a large overstatement of the capacity charges.

The problem on the energy side is that his energy figures are driven by Penelec's 1991 ARPR gas price forecasts which I previously discussed.

Q. HAVE YOU CORRECTED THIS ANALYSIS?

A. I have performed some calculations to show what happens when the gas price forecast embedded in that analysis is revised in accordance with my scenario. Schedule MIK-8 presents that calculation. The first two columns compare my gas price scenario (in $/MMBtu) with GPU's forecast. The third column identifies the $/MMBtu difference. The fourth column translates that into a fuel dollars per year savings for 1 mW of combined cycle capacity. The combined cycle is assumed to operate at a 60 percent capacity factor, or 5,256 hours per year. As this schedule shows for 1997, a reduction of $0.70 per MMBtu translates into a savings per mW of capacity that year of $28,477. The 30-year present value for one mW (at 9.13 percent) is $2 million.

Dr. Venkateshwara claims a present value (1991) savings for Cambria of $18 and $62 million, or $31 million to $104 million if the present value date is 1997. My calculations indicate a present value cost reduction of $2 million per mW over 30 years from correcting the gas forecast. For the 200 mW Cambria contract this is a downward adjustment of $400 million. This offsets his claimed 30-year $105 million savings by a factor of four.

Thus, the "Ratepayers Acceptability Test" provides a present value increase in cost to ratepayers of nearly $300 million before considering any corrections to his capital costs.

Q. DR. VENKATESHWARA ASSERTS THAT THE CAMBRIA OFFER IS BELOW THE PURPA ENERGY ONLY RATES. IS HE CORRECT?

A. The PURPA energy rates which he refers to are based upon Penelec's overstated fuel price assumptions. In response to OCA Set II, item 2, Penelec provided PJM billing rate projections based upon my fuel price scenario. These PJM rates are substantially lower than the "PURPA energy rates" which he cites in his testimony. For example, by 2018, the PJM billing rate using my fuel price scenario is nearly 30 percent below his PURPA energy rate.

PENNSYLVANIA ELECTRIC COMPANY

Cogeneration Contract Offers versus
DRR Avoided Cost Projections
($/Mwh; 10.71% discount rate)

	LG&E	American/ CMS	Cambria	OCA DRR
1997	$73.30	$92.73	$87.40	$57.53
1998	76.40	93.95	89.50	60.25
1999	79.60	95.23	91.85	61.74
2000	83.00	96.57	94.04	63.60
2001	86.50	97.99	96.47	65.61
2002	90.20	99.47	98.95	67.93
2003	94.10	101.02	101.67	70.49
2004	98.10	102.66	104.35	73.59
2005	102.20	104.38	107.38	76.99
2006	106.60	106.18	110.36	80.70
2007	95.30	108.07	113.70	84.42
2008	97.90	110.06	117.00	87.23
2009	100.60	112.14	120.57	92.65
2010	103.50	114.33	124.30	97.87
2011	106.50	116.63	128.20	103.48
2012	121.00	119.05	130.70	108.91
2013	128.10	121.58	133.30	114.13
2014	138.10	124.24	136.10	121.16
2015	147.60	127.04	116.79	128.38
2016	159.90	129.97	119.89	136.86
2017	154.10	133.05	123.09	145.26
2018	166.70	136.29	126.39	154.80
2019	176.00	139.69	129.89	163.10
2020	185.90	143.25	133.59	172.00
2021	196.40	147.00	137.39	181.40
2022	208.20	150.93	141.49	185.90
2023	220.68	155.06	145.69	197.10
2024	233.92	159.40	150.19	208.90
2025	247.95	163.95	154.79	221.40
2026	262.83	168.73	159.69	234.70
Present Value	$1,008.15	$1,049.38	$1,046.05	$833.85
Levelized	$102.36	$106.55	$106.21	$84.67

(1) All calculations assume 80% discount factor.

PENNSYLVANIA ELECTRIC COMPANY

Cogeneration Contract Offers versus
DRR Avoided Cost Projections
($/Mwh; 9.13% discount rate)

	LG&E	American/ CMS	Cambria	OCA DRR
1997	$73.30	$92.73	$87.40	$57.53
1998	76.40	93.95	89.50	60.25
1999	79.60	95.23	91.85	61.74
2000	83.00	96.57	94.04	63.60
2001	86.50	97.99	96.47	65.61
2002	90.20	99.47	98.95	67.93
2003	94.10	101.02	101.67	70.49
2004	98.10	102.66	104.35	73.59
2005	102.20	104.38	107.38	76.99
2006	106.60	106.18	110.36	80.70
2007	95.30	108.07	113.70	84.42
2008	97.90	110.06	117.00	87.23
2009	100.60	112.14	120.57	92.65
2010	103.50	114.33	124.30	97.87
2011	106.50	116.63	128.20	103.48
2012	121.00	119.05	130.70	108.91
2013	128.10	121.58	133.30	114.13
2014	138.10	124.24	136.10	121.16
2015	147.60	127.04	116.79	128.38
2016	159.90	129.97	119.89	136.86
2017	154.10	133.05	123.09	145.26
2018	166.70	136.29	126.39	154.80
2019	176.00	139.69	129.89	163.10
2020	185.90	143.25	133.59	172.00
2021	196.40	147.00	137.39	181.40
2022	208.20	150.93	141.49	185.90
2023	220.68	155.06	145.69	197.10
2024	233.92	159.40	150.19	208.90
2025	247.95	163.95	154.79	221.40
2026	262.83	168.73	159.69	234.70
Present Value	$1,174.11	$1,199.37	$1,196.08	$979.00
Levelized	$105.93	$108.21	$107.91	$88.33

(1) All calculations assume 80% capacity factor.

PENNSYLVANIA ELECTRIC COMPANY

Cogeneration Contract Offers versus
Coal Proxy Cost Projections
($/Mwh; 10.71% discount rate)

	LG&E	American/ CMS	Cambria	Coal Proxy
1997	$73.30	$92.73	$87.40	$85.10
1998	76.40	93.95	89.50	85.00
1999	79.60	95.23	91.85	84.73
2000	83.00	96.57	94.04	84.62
2001	86.50	97.99	96.47	84.67
2002	90.20	99.47	98.95	84.85
2003	94.10	101.02	101.67	85.21
2004	98.10	102.66	104.35	85.74
2005	102.20	104.38	107.38	86.37
2006	106.60	106.18	110.36	87.10
2007	95.30	108.07	113.70	87.94
2008	97.90	110.06	117.00	88.91
2009	100.60	112.14	120.57	89.97
2010	103.50	114.33	124.30	91.16
2011	106.50	116.63	128.20	92.50
2012	121.00	119.05	130.70	93.93
2013	128.10	121.58	133.30	95.53
2014	138.10	124.24	136.10	97.27
2015	147.60	127.04	116.79	99.13
2016	159.90	129.97	119.89	101.19
2017	154.10	133.05	123.09	103.57
2018	166.70	136.29	126.39	106.48
2019	176.00	139.69	129.89	109.78
2020	185.90	143.25	133.59	113.28
2021	196.40	147.00	137.39	116.94
2022	208.20	150.93	141.49	120.83
2023	220.68	155.06	145.69	124.97
2024	233.92	159.40	150.19	129.31
2025	247.95	163.95	154.79	133.87
2026	262.83	168.73	159.69	138.70
Present Value	$1,008.15	$1,049.38	$1,046.05	$883.63
Levelized	$102.36	$106.55	$106.21	$89.72

(1) All calculations assume 80% capacity factor.

PENNSYLVANIA ELECTRIC COMPANY

Cogeneration Contract Offers versus
Coal Proxy Cost Projections
($/Mwh; 9.13% discount rate)

	LG&E	American/ CMS	Cambria	Coal Proxy
1997	$73.30	$92.73	$87.40	$85.10
1998	76.40	93.95	89.50	85.00
1999	79.60	95.23	91.85	84.73
2000	83.00	96.57	94.04	84.62
2001	86.50	97.99	96.47	84.67
2002	90.20	99.47	98.95	84.85
2003	94.10	101.02	101.67	85.21
2004	98.10	102.66	104.35	85.74
2005	102.20	104.38	107.38	86.37
2006	106.60	106.18	110.36	87.10
2007	95.30	108.07	113.70	87.94
2008	97.90	110.06	117.00	88.91
2009	100.60	112.14	120.57	89.97
2010	103.50	114.33	124.30	91.16
2011	106.50	116.63	128.20	92.50
2012	121.00	119.05	130.70	93.93
2013	128.10	121.58	133.30	95.53
2014	138.10	124.24	136.10	97.27
2015	147.60	127.04	116.79	99.13
2016	159.90	129.97	119.89	101.19
2017	154.10	133.05	123.09	103.57
2018	166.70	136.29	126.39	106.48
2019	176.00	139.69	129.89	109.78
2020	185.90	143.25	133.59	113.28
2021	196.40	147.00	137.39	116.94
2022	208.20	150.93	141.49	120.83
2023	220.68	155.06	145.69	124.97
2024	233.92	159.40	150.19	129.31
2025	247.95	163.95	154.79	133.87
2026	262.83	168.73	159.69	138.70
Present Value	$1,174.11	$1,199.37	$1,196.08	$1,004.82
Levelized	$105.93	$108.21	$107.91	$90.66

(1) All calculations assume 80% capacity factor.