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STATE OF TEXAS
PUBLIC UTILITIES COMMISSION

Re: Gulf States Utilities,
Docket No. 3298

JOINT TESTIMONY OF MICHAEL B. MEYER AND PAUL L. CHERNICK ON BEHALF OF EAST TEXAS LEGAL SERVICES

August 25, 1980

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I. INTRODUCTION

Q: Mr. Meyer, would you state your name, occupation, and business address?

A: My name is Michael B. Meyer. I am a principal of the research and consulting firm Analysis and Inference, Inc., 10 Post Office Square, Suite 970, Boston, Mass., 02109.

Q: Mr. Meyer, would you please briefly summarize your professional education and experience?

A: I received a B.A. degree in mathematics from Harvard University in June, 1967 (which I earned in three years) and a J.D. degree from Boston College Law School in June, 1973. I am generally familiar with all aspects of utility regulation. I was an assistant attorney general for the Commonwealth of Massachusetts, specializing in utility and insurance regulation, from May, 1975 to September, 1979, and I was the chief of the Massachusetts Attorney General's utilities division from November, 1977 to September, 1979. In the course of my duties at the Attorney General's office, I served as lead trial counsel in numerous rate cases, rate design cases, long-range energy and demand forecasting cases, utility financing cases, and utility construction audit cases. I additionally was responsible for performing and supervising a wide variety of accounting, economic, and financial analyses of utilities engaged in regulatory proceedings. I have taught six short courses on how to analyze and try utility rate level cases and utility rate design cases for the National Consumer Law Center for legal services attorneys. In my current position, I have advised private clients on a variety of utility matters.

Q: Mr. Meyer, have you testified previously in utility proceedings?

A: Yes. I testified on the subject of peak load pricing, marginal cost pricing, and the need for coordination of the Massachusetts fuel clause statute with proposed rate design reforms, before the Massachusetts Department of Public Utilities in D.P.U. 18810, a rulemaking proceeding considering proposed electric utility rate design reforms. I also testified on the proper accounting treatment for net income resulting from interruptible gas sales before the Massachusetts Department of Public Utilities in D.P.U. 19806A/20147, a rulemaking proceeding considering the standardization of gas distribution companies' purchased gas adjustment clauses.

Q: Mr. Chernick, would you state your name, occupation, and business address?

A: My name is Paul L. Chernick. I am employed as a utility rate analyst by the Massachusetts Attorney General's utilities division.

My office address is One Ashburton Place, 19th Floor, Boston, Mass. 02108. In addition, I am a consultant to the firm of Analysis and Inference, Inc. The testimony I am presenting today represents my own views and opinions, and does not represent the official view, opinion, or position of the Attorney General of Massachusetts. I am currently on vacation from my permanent employment in order to testify here today.

Q: Mr. Chernick, would you please briefly summarize your professional education and experience?

A: I received an S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and a S.M. degree from Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, to membership in the engineering honorary society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi. I am the author of <u>Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions</u>, Report 77-1, Technology and Policy Program, Massachusetts Institute of Technology. During my graduate education, I was the teaching assistant for courses in systems analysis.

I have served as a consultant to the National Consumer Law Center for two projects: teaching part of a short course in rate design and time-of-use rates, and assisting in preparation for an electric time-of-use rate design case. My resume is attached to this testimony as Appendix B.

Q: Mr. Chernick, have you testified previously in utility proceedings?

A: Yes. I have testified jointly with Susan Geller before the Massachusetts Energy Facilities Siting Council and the Massachusetts Department of Public Utilities in the joint proceeding concerning Boston Edison's long-range energy and demand forecast, docketed by the E.F.S.C. as 78-12 and by the D.P.U. as 19494, Phase I. I have also testified jointly with Susan Geller before the Massachusetts D.P.U. in Phase II of D.P.U. 19494, concerning the long-range energy and demand forecasts of nine New England utilities and NEPOOL, and jointly with Susan Finger before the Massachusetts D.P.U. in Phase II of D.P.U. 19494, concerning Boston Edison's relationship to NEPOOL. I also testified before the Massachusetts E.F.S.C. in proceedings 78-17 and 78-33, on the 1978 long-range energy and demand forecasts of Northeast Utilities and Eastern Utilities Associates, respectively. In addition, I testified jointly with Susan Geller before the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission in Boston Edison Co., et. al., Pilgrim Nuclear Generating Station, Unit No. 2, Docket No. N.R.C. 50-471, concerning the "need for power". I recently testified before the Massachusetts D.P.U. in D.P.U. 20055 regarding the 1979 long-range energy and demand forecasts of EUA and Fitchburg Gas and Electric, the cost of power from the Seabrook nuclear plant, and alternatives to Seabrook purchases, and before the Massachusetts D.P.U. in D.P.U. 20248 regarding the cost of Seabrook power. I have also submitted prefiled joint testimony with Ms. Geller in the Boston Edison time-of-use rate design case, D.P.U. 19845, but we have not yet testified in that case. I have also testified on Massachusetts Electric Company's proposed rate design in D.P.U. 200. I have also submitted prefiled testimony on Eastern Edison's proposed rate design in D.P.U. 243, but I have not yet testified in that case.

Q: Are you both responsible for the entire substantive portion of this testimony?

A: Yes. This testimony is a joint effort, and each of us supports every portion of the testimony.

Q: What is the subject matter of your testimony?

A: Every rate case necessarily covers three distinct conceptual subjects:

(1) estimation of total revenue deficiency;

(2) allocation of total revenue deficiency to customer classes (i.e. revenue allocation); and

(3) allocation of revenue deficiency for each customer class to customers (i.e. rate design).

Our client, East Texas Legal Services, asked us to examine GSU's treatment of the second step, the allocation of the total estimated revenue deficiency to customer classes, and the third step, rate design, and to make recommendations on these subjects. We made no analysis, and therefore make no recommendations, on the subject of revenue deficiency (step 1).

II. REVENUE ALLOCATIONS

Q: How does GSU perform its revenue allocations?

A: GSU proceeds in four steps. First, Mr. Smith separates investments and expenses by department (steam, gas, and electric). Second, Mr. Smith separates investments and expenses within electric operations by state (Texas and Louisiana). Third, Mr. Beekman separates investments and expenses within Texas by jurisdiction (Texas jurisdictional and FERC jurisdictional). Fourth, Mr. Beekman separates investments and expenses within the Texas jurisdiction by customer class.

Q: Which of these four steps will you focus upon?

A: The fourth step, Mr. Beekman's separation of Texas jurisdictional electric investments and expenses by customer class. This should not be taken to imply that we necessarily agree with everything GSU did in the first three steps. However, due to the limited time and resources we are able to expend upon this case, we thought it best to assume for the purposes of this case that steps (1) through (3) were done properly, and to restrict our attention to step (4).

Q: Did Mr. Beekman perform step (4), the separation of Texas jurisdictional electric investments and expenses by customer class, in a reasonable manner?

A: In our opinion, he did not.

Q: Please explain your answer.

A: The problem of allocating embedded (or average) costs has troubled accountants and economists for years. The essential problem with attempting to allocate embedded costs is the difficulty encountered in determining how the embedded costs of the utility, incurred over many years under a variety of circumstances, are related to current characteristics of customer classes.

It is instructive to compare the problems faced by marginal-cost and embedded-cost approaches to cost allocation. The marginal analyst really has the easier task: determine how future investments and expenses will vary with customer parameters, such as customer number, KWH consumption (possibly by the time period), non-coincident demand, and coincident demand. In general, only a few new or proposed specific investments of each type (e.g. generating plants) need be examined; the existing plant need not be allocated to classes. If a cost category appears to be independent of specific consumer behavior, the marginalist can properly ignore it completely. While there may be substantial dispute over methodology, the objective of a marginalist allocation is clear and relatively straightforward.

The embedded-cost approach is considerably more exacting. All costs <u>must</u> be allocated, no matter how obscure the relation to customer characteristics. The entire existing plant, old and new, <u>must</u> be allocated. The simple principles characterising marginal allocations become much more complex in the embedded analysis. The question is no longer "What is the cost of serving another KWH or another KW ?" now it is "What would be a fair share of our total costs to attribute to this customer class?"[1]

We understand from conversations with our attorneys from East Texas Legal Services that the Public Utilities Commission of Texas has ruled that embedded costs are to continue to serve as the basis for revenue allocations and for rate design. Given this ruling, Mr. Beekman was necessarily forced to attempt to perform the most reasonable allocation of embedded costs to the various customer classes. Mr. Beekman did this by adopting a large number of more or less arbitrary allocation methods. Investments and expenses were first classified as being demand-related, evergy-related, or customer-related. Second, these investments and expenses, once classified, were then functionalized according to the function served by the investment or expense. Third, once all investments and expenses were classified and functionalized, each category was allocated to one or more customer classes depending upon the nature of the functionalized investment and expense and depending upon the characteristics of the customer classes. See p. DNB-3 to DNB-4. It is important to emphasize that, because most of these investments and expenses in fact represent joint costs (related to providing several services to several classes) and sunk costs (incurred or committed at some time in the past) the process of

1/ In Appendix C, below, we point out that one witness who filed pre-filed testimony in GSU's last rate case, PUCT Docket No. 2677, in fact appears to agree with several of our subsidiary points on why a large portion of generation is energy-related rather than demand-related, but then draws opposite conclusions. That witness also included identifying "fair" portions of costs to allocate to the various classes is inherently somewhat arbitrary. There will often be no fundamental principle to guide these allocations.

Despite the necessarily arbitrary nature of the allocation process, we believe that some allocations can be demonstrated to be more reasonable than others. In other words, although all embedded cost allocations are to some extent arbitrary, within the framework of embedded costs, some embedded cost allocations are less arbitrary than others.

In particular, there are situations in which it is clear that a particular cost was incurred for a particular purpose, or that a given portion of installed plant is providing an identifiable service. In such cases, a fair and reasonable allocation should follow the purpose and use of the cost as closely as possible.

Q: Could you please give specific examples of what you consider to be unreasonable cost allocations of Mr. Beekman?

A: Yes. We have selected three areas for specific comment: (1) the allocation of investment and expenses for the production power supply function based upon the average and excess (A&E) allocation method based upon pro-rated non-coincident class peaks; (2) the allocation of transmission and distribution facilities (230KV and above, 138KV, subtransmission, 34KV, and primary facilities) based upon the A&E allocation method; and (3) the allocation of tie-line facilities.

(footnote continued)

some language in that testimony that in fact supports the application of marginal, rather than embedded, costs as the basis of rate design. See Appendix C, below.

In each situation, Mr. Beekman appears to have understated the extent to which costs vary with energy consumption, and overstated the extent to which costs are related to peak demand.

A. Investment and Expenses for the Production Power Supply Function

Q: How does GSU allocate investment and expenses for the production power supply function?

A: This is explained in Mr. Beekman's testimony on pp. DNB-5 to DNB-6, and in WP 79-8010. Essentially, these costs are largely allocated by the class average loads, and by the class excess loads indicated by non-coincident class peaks, which are reduced by a scaling factor (p. DNB-6, lines 5-9).

Q: What in your opinion is incorrect about this methodology?

A: This methodology ignores the origin of investment and expenses for the production power supply function and substantially under-estimates the proportion of these costs which are in fact energy, rather than demand, related.

Q: Please explain why this is true.

A: The investment and fixed operating costs relating to generation are not caused solely, or even largely, by peak demands. Utilities like GSU attempt to minimize total generation costs, including both fixed and variable costs, over all 8760 hours of their annual load duration curve (LDC). If a utility wished to construct generation capacity just to serve its annual peak (or, in this case, just its four summer months' peaks), it would construct far more capital-inexpensive, and fuel-expensive, capacity, like combustion turbines. However, GSU, like all other large utilities, finds it worthwhile to invest in far more capital-intensive generating facilities with lower fuel costs in order to serve all KWH's and all KW's (no matter where they appear on the LDC) more economically. As a result, a very substantial proportion of production power supply costs are in fact energy-related, rather than demand-related.

Q: Please go into more detail on the subject of why utilities invest in different types of generating facilities.

A: There are two basic reasons for a utility investing in generating facilities. First, generators are built to maintain or increase system reliability, that is, the probability that customer demand can be met by available generating capacity at any particular instant. Second, more expensive generating facilities are built to allow for more economical operation, that is, so that they can burn cheaper fuel and/or burn fuel more efficiently.

For example, GSU estimates that it can build combustion turbines for $233/KW. GSU 1979 FERC-1, p. 109E. Nevertheless, GSU is building coal-fired plants at cost of around $800/KW, lignite-fired plants at costs of about $1400/KW, and a nuclear unit at a cost of $1839/KW, even though these plants take longer to build (during which time GSU's customers must pay interest charges) and even though these plants will support less firm demand per KW of installed capacity than do combustion turbines. The higher capital cost is accepted as a tradeoff for lower heat rates and less expensive fuel.

Q: Is the generation capital cost which is related to reliability determined solely by peak demand?

A: Absolutely not, for at least three reasons. First, modern utility systems (such as GSU) base their reliability requirements on a loss-of-load probability (LOLP) target, which requires that the expected number of hours of generation supply inadequacy over the course of a particular planning horizon (usually a year) be less than that target. GSU, as a part of the SWPP, uses a LOLP target of one day in 10 years, although it does not appear to be meeting that goal in the near future(see p. AEN-6). As Mr. Naylor explains, load shape affects the difficulty of maintaining system reliability (see p. AEN-9). Everything else being equal, higher reserve margins and hence more capacity are required for systems with high load factors and many hours per year with demand near the system peak than for systems with low load factors and with sharply spiked load curves. Figure 1 is an illustration of the latter sort of system, and Figure 2 is an illustration of the former, although both are hypothetical extremes. System 1 has only 100 hours which are vulnerable to supply inadequacy; if 10,000 MW of reasonably reliable capacity is installed, the probability of losing load in the low-demand hours is negligible. Therefore, for System 1, a "1 day in 10 years" LOLP criteria essentially means

"24 hours of LOLP in 1000 hours (10 years x 100 hours/year) at or near full load." Therefore 2.4% of the high-load hours can result in load-shedding without violating the LOLP target.

By comparison, for System 2 in Figure 2, 1000 hours/year are at risk, so the permissible rate of supply inadequacy is lowered to only 0.24% of the high-load hours, if the target LOLP is to be maintained. Therefore, System 2 will require a higher reserve margin to achieve a target LOLP than will System 1; this result is an effect of the off-peak hours' demand on additional capacity.

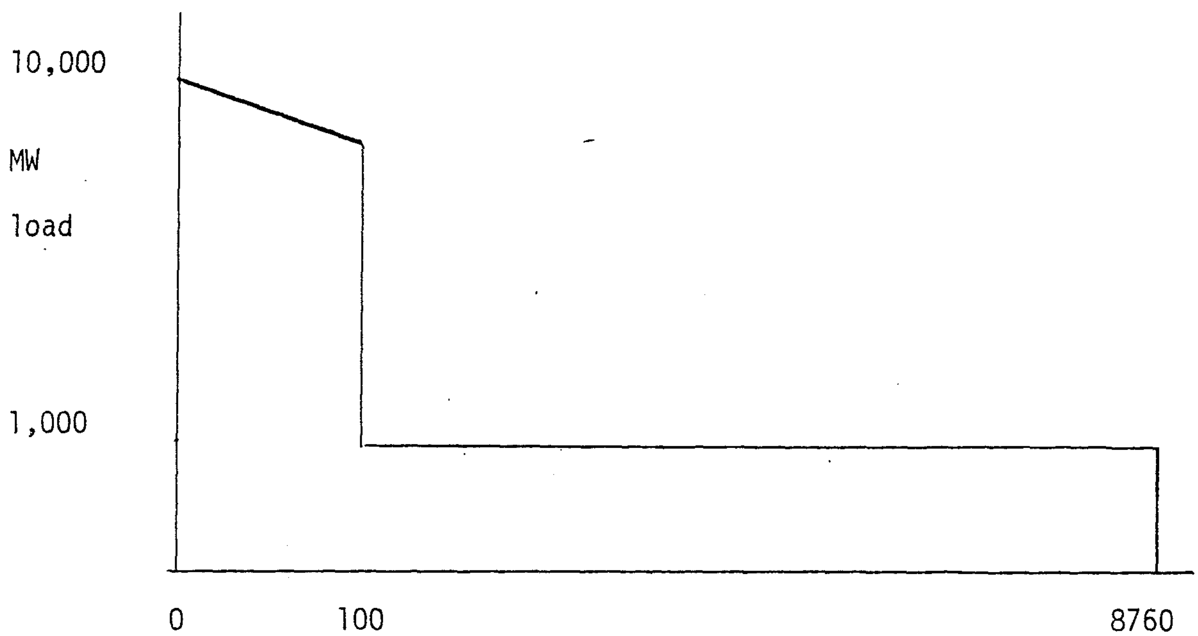

Figure 1: System 1's Load Duration Curve

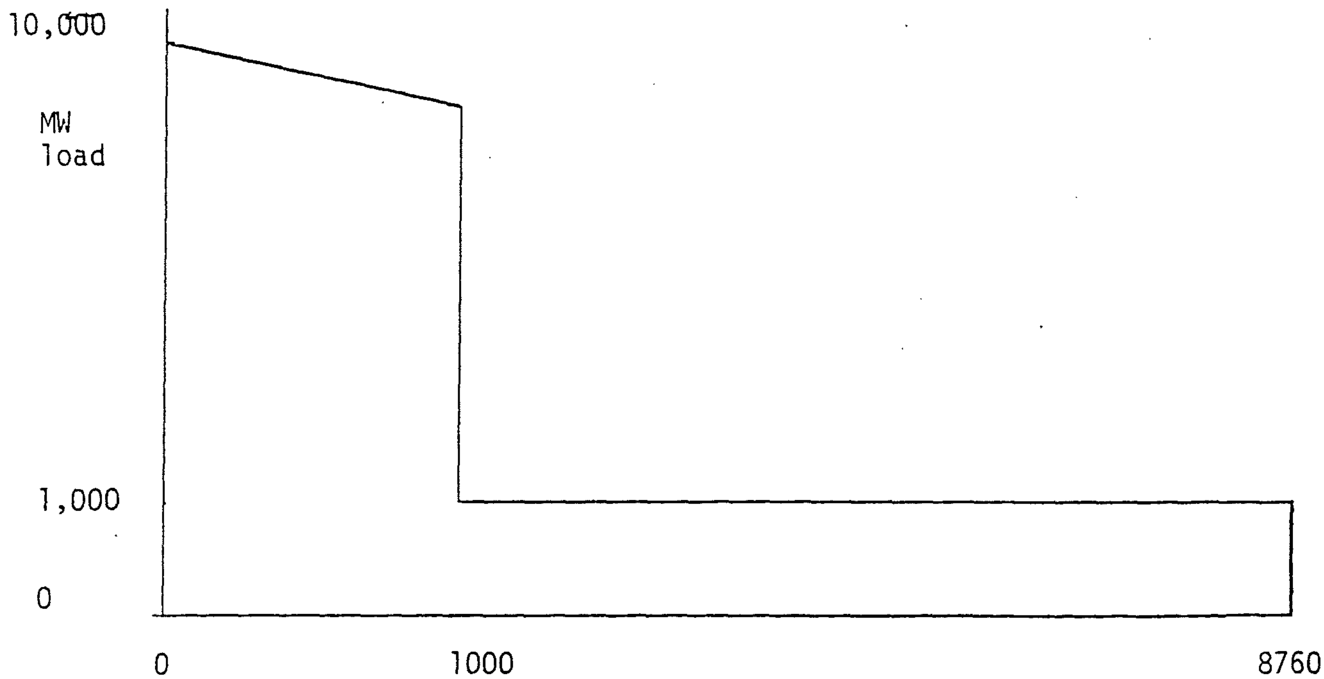

Figure 2: System 2's Load Duration Curve

Second, higher load factors require the installation of additional capacity to allow for maintenance of generating units. System 3 in Figure 3 is a hypothetical example of a system unconstrained by maintenance requirements. Monthly peaks in seven months (October- April) are far below the annual peak. Even allowing for overruns, several large generators might be removed for maintenance during the offseason, without substantially impacting system reliability or the attainment of target LOLP.

By comparison, hypothetical System 4 in Figure 4 does not have the same long, deep valley. As a result, only a small number of generating units could be removed from service simultaneously for maintenance without increasing LOLP. Depending on the size, number and type of generators, it might not be possible to schedule them all for maintenance without appreciably increasing LOLP and therefore requiring additional capacity.

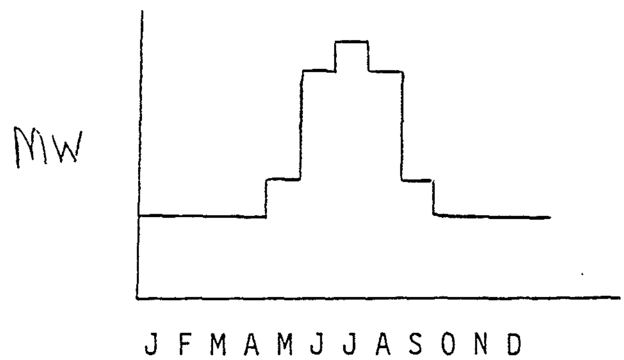

Figure 3: System 3's Annual Load Curve

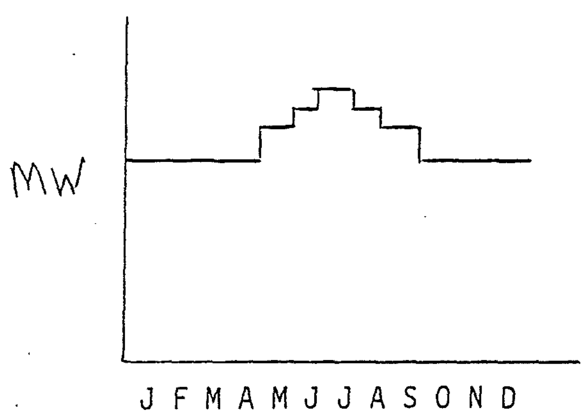

Figure 4: System 4's Annual Load Curve

A utility with a high load factor, and more specifically, consistently high monthly and weekly peaks, therefore requires a higher reserve margin than a low load-factor utility. This tendency extends to weekly load curves; a utility with consistently low demand on weekends (even in peak months) may be able to schedule some maintenance during those times without requiring additional capacity, while a utility with higher weekend demand might not be able to do so. Therefore, required reserves are also increased by demand in off-peak weeks and months, and by demand on weekends, even if these demands do not contribute substantially and directly to LOLP.

Third, capacity must be more durable if it is to meet demand throughout the year, rather than for just a few peak hours. Even peaking plants, such as gas-fired combustion turbines, are typically expected to be able to function up to 1500 hours per year. While it is difficult to quantify the exact cost effect of this durability requirement, it is clear that providing reliable service outside a few peak hours must require some additional capital investment. Furthermore, a portion of O & M and capital additions are also due to the amount of use that a generating unit receives and of the resultant wear and stress on components.

Q: Why do coal and nuclear plants support less firm demand than would be supported by an equivalent MW capacity of gas-fired combustion turbines?

A: There are three basic reasons. First, large steam units tend to have larger forced outage rates than small peaking units. Second, large steam units have large maintenance requirements; for example, scheduling a 2-3 month refueling outage for a nuclear unit(within the constraints of fuel life) may place considerable stress on system reliability. The combined effect of these outages may be seen in the projections of capacity factors and related parameters for large units tabulated in Table D-2. Third, independent of forced outage rates and scheduled maintenance requirements, the very size of large units reduces their contribution to system reliability. This effect can be illustrated by the following simple example.

Consider a system with a 2000 MW system peak and with 3000 MW of installed capacity. If that capacity is composed of three 1000 MW plants, each with a 10% forced outage rate, the probability of not meeting peak demand (that is, the probability that 2 or 3 plants will be out) is 0.028:

$$LOLP=(3x.9x.1x.1) + (1x.1x.1x.1)$$

$$LOLP= \quad 0.027 +0.001$$

$$LOLP= \quad 0.028$$

which is equivalent to 10.22 days/year, or 1 day in 0.0978 years. By contrast, if the 3000 MW of installed capacity is made up of 60 plants of 50 MW each, with each plant still having a 10% forced outage rate, the probability of not meeting peak (which now requires 21 or more (of 60) simultaneous outages) is only on the order of 1.57×10^{-7}:

$$LOLP = \sum_{i=21}^{60} \left[\frac{60!}{i!\,(60-i)!} \right] (.1)^{i} (.9)^{60-i}$$

$$LOLP = 1.31 \times 10^{-7} + 2.58 \times 10^{-8} + 4.74 \times 10^{-9} + \ldots$$

$$LOLP \approx 1.57 \times 10^{-7}$$

which is equivalent to 0.0000573 days (about 5 seconds) per year, or 1 day in 17,452 years.

This hypothetical example is somewhat extreme,but it illustrates the general point: Large generators require more reserve capacity than small generators, even if all other factors, such as their forced outage rates, are equal. Thus a MW of capacity from a large generator has a smaller effective load carrying ability than a MW of capacity from a small generator, even if their forced outage rates are equal.

Q: Can you quantify the difference in the load-carrying ability of peaking and base-load capacity for GSU?

A: Unfortunately, GSU has not attempted to estimate the effective load-carrying capability (ELCC) on its system of various types and sizes of generators, apparently because GSU has not yet realized that ELCC varies with size and type of generating facility. See Information Response of GSU to ALL UPSET No. I-15. While the ELCC of generators differs from one utility system to another, the ELCC of large units can be estimated from studies done on other utilities, and the ELCC of small units can be estimated directly. In Appendix D we present evidence that, even on much larger systems, the new baseload facilities which GSU is building would have ELCC's of only about half their rated capacity, while gas turbines operated as peakers appear to provide an ELCC well in excess of 80% of rated capacity.

Therefore, a MW of base-load coal or nuclear capacity replaces only about 0.6 MW (i.e. 0.5 ÷ 0.8 = 0.6) of gas turbines, in terms of its ability to support reliable service.

Q: Given this discussion, what portion of the capital cost of a generator is properly attributable to reliability?

A: The entire cost of peaking units, such as gas-fired combustion turbines or oil-fired diesels, plus the cost of hypothetical peaking capacity equivalent to about 60% of the rated capacity of baseload units. The cost of the hypothetical turbine capacity to be attributed to the reliability -serving portion of base-load capacity, depends upon the vintage of the base-load units. For each of the GSU's existing units built after 1962, we estimated the capital costs of a comparable gas turbine in \$/KW as

1) \$233/KW	Cost \$/KW of gas turbine, 1982, from GSU 1979 FERC-1,p. 109E
2) ÷ $(1.08)^3$	8% inflation, 1979 - 1982, from Info. Response V-1
3) ÷303xHW(COD)	Inflation, COD to 1979, from Handy-Whitman Index,1957-59=100
4) X ELCF	Effective load carrying factor

For the existing gas/oil plants, we assumed a substantial advantage in ELCC compared to coal or nuclear plants, so that the ELCF is 0.7 for units over 550 MW. We also optimistically assumed that very small steam plants would have ELCC's comparable to gas turbines, so that ELCF for 50 MW (and smaller) units is 1.0. We then interpolated linearly between these two values for each unit. This calculation is detailed in Appendix E. We made no adjustments for units built before 1/1/63, and attributed them entirely to reliability, although this also overstates the reliability portion of generation investment.

According to the calculations in Appendix E, Table E-1, approximately 67.0% of the $336,587,424 electric production plant in service in the Texas retail rate base (=$1,197,305 + $335,390,199; see WP-79-1100, p.1 of 5, line 10, cols.4 and 5) is attributed to reliability, and 33.0% is due to energy. GSU's allocation is 0.4% to energy and 99.6% to reliability. See WP-79-1100, p.1 of 5, line 10, cols. 4 and 5.

Similar adjustments (which will partially offset the electric plant in service adjustment) should be made to GSU's allocation of accumulated depreciation. GSU allocated production power supply accumulated depreciation 0.5% to energy and 99.5% to demand; (See WP-79-1400, p. 1 of 5, line 10, cols. 4 and 5). We recommend, for the same reasons explained above for production power supply electric plant, that this allocation be modified to 33.0 % to energy and 67.0 % to demand. Similarly, for three other items (accumulated deferred F.I.T., depreciation expense and property taxes) we recommend that GSU's allocations be replaced by our allocations for production power supply electric plant in service,as follows:

GSU Recommendations

	Energy	Demand
Accumulated Deferred F.I.T*	0.2%	99.8%
Gross Depreciation Expense**	0.6%	99.4%
Property Taxes***	0.2%	99.8%
Depreciation Expense due to CWIP in Rate Base****	0%	100.0%

*From WP-79-1740, p. 1 of 6, line 10, cols. 4 and 5

** from WP -79-3140, p. 1 of 5, line 10, cols. 4 and 5

***from WP-79-4140, p. 1 of 5, line 10 cols. 4 and 5

****From WP-79-3180, p. 1 of 5, line 10, cols.4 and 5

We recommend that the first three items listed above (accumulated deferred F.I.T., gross depreciation expense and property taxes) be allocated with the same proportions as we recommended for production power supply electric plant in service, i.e. 33.0 % to energy and 67.0 % to demand, and that the fourth, depreciation expense due to CWIP in rate base, be allocated with the same proportions as we recommend below for production power supply CWIP, i.e. 98.2% to energy and 1.8% to demand.

In addition to lower capital costs, the hypothetical gas turbine peaking systems would be cheaper to operate and maintain. As Table E-2 shows, gas turbines cost \$330 - \$3000 /MW-year in non-fuel O & M. For GSU's existing plants, these figures are \$5400 - \$22000/MW -year, due to the greater complexity of the plants(see Table E-3, Appendix E). A system of gas turbines of reliability equal to GSU's current system would cost about \$6,053,442/year at the average cost shown in Table E-2. This figure, derived in Table E-4, is equivalent to 14.4% of GSU's \$42,032,998 generation non-fuel O & M expense for 1979. This suggests that the Texas portion of Steam Power Expense, which GSU allocates 34.5% to energy and 65.5% to reliability (\$6,464,645 and \$12,276,317 respectively; see WP - 79- 2000, p. 1 of 20, line 13, col. 4 and line 14, col. 5) would more properly be allocated 85.6% to energy and 14.4% reliability (or \$16,042,263 and \$2,698,699 respectively).

For the future coal and nuclear units included in CWIP in this case, we had to determine the extent to which peakers with the same in-service date would be built as of 12/31/79, the end of the test year. We assumed that such hypothetical plants would be built in 36 equal installments over a 36-month period, based on GSU's estimate that GSU could build a turbine plant in three years. (GSU 1979 FERC-1, p. 109E). This implies, of course, that gas turbines scheduled for service past December, 1982 would not appear in a 1979 test year rate base at all and thus would not appear in CWIP at all. Therefore, the fact that any unit scheduled for service after that date is currently in CWIP is due entirely to its energy-related function. For base-load units scheduled to be in commercial operation before 12/31/82, we attributed the following amounts to the reliability-serving equivalent:

1) \$233/KW — \$KW cost of gas turbines, December, 1982

2) x $(1.08)^{COD-1982}$ — inflation 12/31/1982 to COD

3) x 0.6 — ELCF

4) X (1982 - COD) ÷ 3 — fraction of equivalent turbine complete in 1979, to be in test year CWIP rate base

5) X 1000 x MW — 1000 x MW rating of plant

Eight generating units are listed in Information Response V-1 of GSU to All UPSET as contributing to CWIP. Of these, two units (Nelson 7 and Willow Glen 6) are peakers, and are thus properly allocated on a reliablity basis. Four other units (River Bend 1, River Bend 2, Nelson 5 and Lovelady 1) are base-load, and are scheduled for initial operation after 12/31/82, so all of their costs at this point (i.e. as of 12/31/79, the end of the test year) are properly attributable to energy:

River Bend 1	\$451, 841,000
River Bend 2	\$ 63,172,000
Nelson 5	\$ 11,549,000
Lovelady 1	\$ 20,000
	\$526,582,000

One base-load unit (Sabine 5) is a completed oil/gas unit, and is treated as such above. One unit, Nelson 6, a 540 MW coal plant in which GSU owns a 378 MW share, is due in service as of 3/82, and thus has an equivalent gas turbine cost of

$$\$233 \times (1.08)^{-0.75} \times (0.6) \times (0.75 \div 3) \times 1000 \times 378$$

or \$12,470,000, leaving the remainder of \$149,031,000 of Nelson 6 cost as energy-related. The results of these calculations for the eight units in CWIP as of 12/31/79 can be summarized as follows:

Unit	Energy-Serving Portion	Reliability-Serving Portion	Total
Nelson 7	0	38,000	\$ 38,000
Willow Glen 6	0	48,000	48,000
River Bend 1	\$451,841,000	0	451,841,000
River Bend 2	63,172,000	0	63,172,000
Nelson 5	11,549,000	0	11,549,000
Lovelady 1	20,000	0	20,000
Nelson 6	149,031,000	12,470,000	161,501,000
Total	675,613,000	12,556,000	688,169,000

In other words, 98.18% of production power supply CWIP should be allocated to energy, and 1.82% should be allocated to demand. This contrasts sharply with GSU's recommendation (see WP-79-1300, p.1 of 5) in which 0.08% of production power supply CWIP is allocated to energy and 99.92% of production power supply CWIP is allocated to demand (see WP-79-1300, p. 1 of 5, line 10, cols. 4 and 5).

Q: Should the reliability -related portion of generator cost be assigned solely on the basis of peak demand?

A: No. As we explained previously, many hours of demand other than peak demand hours (either annual or monthly peak hours) require additional investment in generating capcity, to maintain LOLP, to allow for maintenance, and to provide durability. Properly speaking, the reliability - related investment in generation should be allocated on the basis of the contribution of demand in various hours to capacity requirements (for maintaining LOLP and for allowing for maintenance) and to durability investments. Unfortunately, GSU has not even taken the first step in this process, a disaggregation of LOLP by time-of-day, day-of -week, and season of year. See Information Response of GSU to ALL UPSET No. I-5. Once this analysis is complete, and once the load research data required by PURPA is available, it will be easy to determine the contribution of each class to the need for reliability- related generation investment.

In the meantime, some surrogate allocation method must be selected which recognizes the influence of both peak demand and the rest of the load curve in requiring reliability -related generation investment.

For convenience, we will use the same average-and-excess allocators used by GSU for this portion of total generation investment.

Q: Do you have any comments on any other of GSU's allocations?

A: Yes. First, we should make clear that, to the extent that we do not make specific mention of any of GSU's allocations, we have accepted GSU's allocators. We have done this either where we agree with GSU's allocations, or where we disagree with them, but a correction would be too difficult or would require data unavailable to us. In any case, we adopt all of GSU's allocations not specifically modified herein. One final minor adjustment is to GSU's nuclear fuel in progress allocation (see WP-79-1030 and WP-79-1250). GSU allocates all nuclear fuel in progress as demand related (allocation reference 16), which is improper. All is properly energy-related. GSU appears to have adopted the proper general principle, that fuel inventory is all energy-related, in their allocation of fuel oil inventory as being all energy-related (allocation reference 15) (See WP-79-1040, p. 1 of 1). However, GSU for some reason went the other way with respect to nuclear fuel in progress. In addition to this general principle, it is noteworthy that, if River Bend were replaced by peaking units, no similar fuel inventory would be necessary at this point, so this nuclear fuel in progress is due to the fuel-cost-saving function of nuclear units. We recommend that all fuel be allocated 100% to energy, as GSU has already done with fuel oil inventory.

The reasoning applied in determining our CWIP allocations also applies to the amortization of the Blue Hills project. These expenses were incurred for the purpose of providing low-cost baseload power, and the investments being written off would not have been incurred for peaking units. Therefore, 100% of the Blue Hills loss is energy-related. By contrast, GSU recommends that this amortized loss be 100% allocated to demand. WP-79-3200, p. 1 of 1, col. 3.

Q: Would you please summarize your recommendations contained in this section of your testimony?

A: Yes. With respect to production power supply, we recommend that the "energy" portion continue to be allocated by allocation reference 15, and that the "demand" (what we have termed "reliability") portion continue to be allocated by allocation reference 16, which is GSU's averag and-excess allocator string. However, for the allocation between production power supply energy and production power supply demand (columns (4) and (5) of GSU's standard allocation printouts) we recommend the following allocations, which have been explained and derived previously;

Production Power Supply:	Our Recommendation:		GSU Recommendation:	
	Energy	Demand	Energy	Demand
Electric Plant in Service	33.0%	67.0%	0.4%	99.6%
CWIP	98.2%	1.8%	0.1%	99.9%
Non-Fuel O & M	85.6%	14.4%	34.5%	65.5%
Nuclear Fuel in Progress	100%	0%	0%	100%
Accumulated Depreciation	33.0%	67.0%	0.5%	99.5%
Accumulated Deferred F.I.T	33.0%	67.0%	0.2%	99.8%
Gross Depreciation Expense	33.0%	67.0%	0.6%	99.4%
Property Taxes	33.0%	67.0%	0.2%	99.8%
Depreciation Expense due to CWIP in rate base	98.2%	1.8%	0 %	100%
Blue Hills Amortization	100.0%	0.0%	0.0 %	100.0%

B. Investments and Expenses for Transmission and Distribution Facilities (Excluding Tie Lines)

Q: How does GSU allocate investment and expenses for transmission and distribution facilities?

A: This is explained in Mr. Beekman's testimony at p. DNB-5, lines 5-20. Basically, GSU employed the average-and-excess method to allocate all demand-related transmission and distribution functions. Line transformers are allocated by demand-related and customer-related components using the so-called "zero-intercept" method (DNB-8, line 19 to DNB-9, line 2). This means that essentially all transmission and distribution investments are allocated as either demand-related or customer-related.

Q: In your opinion, is this appropriate?

A: No. There is no question that some transmission and distribution investment is energy-related. When a utility like GSU plans its T&D system, and when it sizes its conductors and transformers, substantial attention is necessarily and properly paid to minimizing system line and transformer losses. Thus it often makes sense to install somewhat larger capacity T&D conductors, and somewhat larger capacity transformers, than that absolutely necessary to serve peak demand, so that total expenses can be minimized by reducing line and transformer losses.

Q: Other than the direct sizing of T&D components to lower KWH losses, are there other reasons to believe that transmission lines are not entirely reliability-related?

A: Yes. In many cases, transmission lines and substations are built or upgraded either to connect large baseload facilities to the general transmission grid, or to strengthen the grid to tolerate large power flows from major central stations to load centers. Much of this transmission investment would not be required for a system composed of small peaking units, located near the load centers in relatively small plants. Therefore, some large portion of the transmission system is due to construction of baseload plants, and is therefore attributable to energy, not demand.

Q: Does GSU agree that it takes line and transformer losses into account in planning its T&D system?

A: No. GSU claims to totally ignore KWH's in sizing T&D elements such as conductors and transformers. See Information Response of GSU to ALL UPSET No. I-16. If Response No. I-16 is taken literally, it means that GSU expends absolutely no effort to minimize line losses occurring at any time other than the time of the annual peak load on each particular transmission or distribution element when GSU sizes its conductors and transformers. If believed by the P.U.C., this would appear to be evidence of lack of effort in minimizing line losses on the part of G.S.U. However, we do not think that Response No. I-16 should be taken literally, and we prefer to believe that Response I-16 was simply answered carelessly. Similarly, Information Response of GSU to ALL UPSET No. I-17 claims that GSU ignores KWH's, and only takes into account peak KW's and customer distribution, in sizing and spacing distribution transformers.

Q: Given the fact that GSU claims to ignore KWH's in sizing conductors and transformers, are you able to quantify the portion of T&D investment that you believe is properly energy-related?

A: No. Beyond stating the obvious, that in a properly-designed utility system T&D conductors and transformers are sized with some consideration being given to KWH's as well as to peak KW's, and that therefore some portion of T&D investments are properly energy-related, we are not able to make any recommendation concerning how the energy-related portion of T&D investment should be quantified.

Q: What do you recommend?

A: We recommend that the P.U.C. order GSU in its next rate case application to either (1) explain in detailed and quantitative terms how KWH's are taken into account in sizing T&D conductors and transformers or (2) explain how GSU can conceivably be minimizing line losses without taking KWH's as well as peak KW's into account. Further, GSU should be instructed to differentiate its transmission system into reliability-serving and energy-serving components. In the meantime, we recommend adopting GSU's allocators for those investments, as GSU's Information Responses I-16 and I-17 simply do not provide a trustworthy basis for an improved allocation method. Finally, the P.U.C. should recognize that the current GSU allocation method necessarily underestimates total energy costs and overestimates total demand and/or customer costs (assuming all other allocations are done perfectly) due to the failure of GSU to allocate any portion of T&D investment as energy-related.

C. Investments and Expenses for Tie Lines

Q: Is GSU's allocation of tie line investments and expenses correct?

A: It does not appear to be. Since tie lines serve numerous functions (e.g., buying and selling power on a firm, economy, emergency, and/or surplus basis), it is difficult to assign their cost to particular purposes. In any case, the past, current, and future uses of the lines may differ, as may the planned and actual uses.

None the less it is clear that GSU's tie lines are providing considerable energy-related services, as Table II-C illustrates.

Q: Please explain the purposes which tie lines serve.

A: A tie line may carry power for any of a number of purposes and on several time patterns, including:

(1) Emergency power, made available only to maintain operating reserve or prevent customer disconnection;

(2) Economy power, made available when the seller can generate more cheaply than the buyer;

(3) Outage power, provided under special conditions and rates to replace power from units which are being maintained or repaired; and

(4) Firm power, available continuously or in proportion to the availability of particular generators.

Power may also be provided for transmission across tie lines only in certain months, or hours, or with particular advance notice. Also, power may flow into the utility, out of it, or through it in a wheeling situation.

Construction of tie lines may be justified, in part or in whole, by any combination of these purposes. The justification may differ from one time period to another, and the expectation during the planning process may differ from the reality in operation.

For example, a utility may build tie lines in the expectation that they will be justified by revenues from off-system sales of power from new oil fired plants the utility plans to build. By the time the tie lines are completed, rising oil prices may have forced cancellation of the oil plants, and the utility may actually use the lines to import firm and off-peak coal-fired electricity from its neighbors, as an economy measure. A few years later, in a regional capacity deficiency, the lines may be useful primarily to allow utilities to support one another with emergency power. As the installed capacity catches up with demand, the lines may serve more as part of an economy central dispatch or brokerage system for the region, lowering participant fuel costs. In each period, the lines may be fully cost effective, but for very different reasons.

Q: On what basis should the tie lines be allocated?

A: The most equitable allocation methodology would be to determine the dollar reliability benefits (e.g., peaking capacity displacement) and the dollar energy benefits (e.g., decrease in final costs), and to allocate the costs in proportion to the benefits. Since such a quantification has not yet been performed, an arbitrary allocation must be used in this case.

Q: What are your recommendations for the allocation of investments and expenses for tie lines?

A: Unless GSU can supply more information than they have to date on the use of the tie lines (see Information Response I-13), we would recommend a 50/50 split between energy and reliability. The 50% allocated to energy would then be allocated to customer classes based on their KWH usage, and the 50% allocated to reliability would be allocated to customer classes using GSU's A&E allocation method. We also strongly recommend that GSU initiate a study to facilitate a more precise allocation of the tie lines on the basis of their beneifts.

Purpose	Category	1979 MWH Imported	Exported
Reliability Only	Emergency	593,639	6,871
Reliability & Energy	Firm (1)	723,906	-
	Replacement	1,853,498	-
	Diversity	279,500	236,919
	Subtotal	2,856,904	236,919
Energy Only	Surplus	2,471,127	-
	Economy (2)	190,564	-
	Subtotal	2,661,696	

Table II-C: Energy carried on GSU's tie lines in 1979 from Information Response I-13 of GSU to ALL UPSET

Notes: (1) Net of station service
(2) Excludes Allied Chemical

III. Residential Rate Design

Q: What does GSU recommend be done with its residential rate, Schedule RS?

A: GSU recommends an increase in the customer charge from $5.00 to $7.00 per month, which includes payment for the first 50 KWH/month, and recommends a flat per-KWH charge of 3.92 ¢/KWH for June-October and of 3.38¢/KWH for November - May. See p. DNB-15, and Vol. V, Section III, Schedule RS.

Q: Do you have any comments upon this proposed residential rate design?

A: Yes. First, we agree with two features of the proposed rate: (1) the fact that the per-KWH charge remains flat, and neither increases nor decreases after the first 50 KWH/ month; and (2) the fact that a summer-winter per KWH charge differential is built into the rate. We also agree that the experimental rate A2 within Schedule RS should be retained as a worthwhile conservation incentive.

However, the customer charge portion of this proposed rate is in our opinion inappropriate for several reasons. First, and somewhat less importantly, the inclusion of the first 50 KWH/month usage in the customer charge completely eliminates the incentive for any connected customer not to waste the first 50 KWH/month whether or not the customer wants them. This might be applicable in the instance of a temporarily unoccupied house or apartment. At the very least, it makes sense to subtract out the flat per-KWH charge for the first 50 KWH/month from the customer charge, and to then start charging for all usage starting with the first KWH each month.

It is appropriate here to note a peculiarity of GSU's proposed residential rate in this respect: the proposed rate design implies that GSU's customer costs (reflected in the "pure" customer charge) per residential customer are actually lower in the summer than in the winter, a result that is certainly both unintended and incorrect.

GSU's implied summer "pure" customer charge

= \$7.00 - 50 (3.92¢)

= \$7.00 - \$1.96

= \$5.04

GSU's implied winter "pure" customer charge

= \$7.00 - 50(3.38¢)

= \$7.00 - \$1.69

= \$5.31

Second, and considerably more importantly, we do not agree with the size of the customer charge. GSU admits that at least some of the reasoning behind distribution system transformer sizing relates to customer proximity and customer geography. Information Response of GSU to ALL UPSET No. I-17. This Information Response

I-17 implies that, for residential customers in very densely populated residential areas, the distribution tranformer investment is completely or almost completely demand-related. Conversely, for residential customers in rural areas, who are quite dispersed geographically, this Information Response implies that a large portion of distribution transformer investment is customer-related. The problem here is thus one of geography: allocating a part of distribution transformer investment as customer-related makes some sense for some of GSU's residential customers (the rural customers) but makes little or no sense for some others (the urban or suburban customers). Similar, if less clear, facts undoubtedly also apply to distribution conductors. Hence, as GSU obviously (and properly) wishes to have a uniform residential rate regardless of a residential customer's geographical location, GSU is faced with a dilemma: no one uniform residential rate can properly reflect economic and engineering reality for all residential customers. We would suggest that, given the complete lack of conservation incentives contained in customer charges, given GSU's current apparent generation capacity shortage, and the concomitant need for GSU to stimulate conservation, any uncertainty or contradictory considerations be resolved against customer charges and for demand and/or energy charges.

Contrary to this serious need for GSU to increase conservation incentives is GSU's pattern of proposed residential rate increases and their percentage increases:

	Current Rate	Proposed Rate	Proposed % Increase
Customer Charge	$5.00	$7.00	40.0%
Winter per-KWH Charge	2.32¢	3.38¢	45.7%
Summer per-KWH Charge	2.85¢	3.92¢	37.5%

As the above table makes clear, GSU is proposing to increase its residential customer charge faster than its summer per-KWH charge, an illogical result for a company like GSU which has strong reasons to stimulate customer conservation.

Q: Can you quantify precisely the amount of the customer charge that GSU is proposing for residential customers that is not properly customer-related for at least some of GSU's residential customers?

A: No, but it is not insubstantial. A very rough estimate would be as follows:

1) total Texas retail electric distribution cost of service allocated to residential customer class as customer-related (from WP-79-7020,p.4 of 6, col. 19, line 1) $2,565,419

2) total Texas retail electric cost of service allocated to residential customer class as customer-related (from WP-79-7020, pp. 4-5 of 6, cols. 19-21,24-25)	$15,732,594
3) % of residential customer cost of service that is not customer related for at least some GSU residential customers ((1) ÷ (2))	16.3%

This estimate of 16.3% may be somewhat high because some relatively minor portion of the distribution cost of service contained in the $2,565,419 figure may in fact be properly customer-related for all residential customers, although this is not likely to be a large amount.

Q: What do you recommend that GSU charge as a residential customer service charge?

A: We recommend that GSU charge no more than about $4.34¢/month as a "pure"residential customer service charge (i.e. one that does not include payment for the first 50 KWH/month). This number is calculated as follows:

1)	GSU's proposed "pure" summer customer charge (from above)	$5.04
2)	GSU's proposed "pure" winter customer charge (from above)	$5.31
3)	GSU's proposed "pure" average customer charge(((1) + (2)) ÷ 2)	$5.18
4)	Proportion that is customer related for all GSU residential customers (1-0.163)	.837
5)	Recommend "pure" average residential customer charge ((4) x(5))	$4.34

We would like to emphasize that this $4.34 is a maximum recommendation. This results because any doubt whatsoever concerning whether a cost is customer-related or not should be resolved against its being customer-related and for its being demand-related or energy-related due to GSU's generation situation, due to GSU's resulting need to impose conservation incentives, and due to a customer charge's complete inability to transmit price signals concerning conservation incentives to customers.

Q: What do you recommend be done with the summer-winter differential?

A: GSU has recommended that the summer-winter differential be reduced:

	Summer	Winter	Differential
Current Rate	2.85¢/KWH	2.32¢/KWH	22.8%
Proposed Rate	3.92¢/KWH	3.38¢/KWH	16.0%

We do not see any convincing reason in GSU's load curves or in what their likely LOLP's are in summer and winter months that would justify reducing this differential. Again, we think GSU's current generation situation and the attendant need for conservation in the summer argues strongly on this point against reducing this summer-winter differential.

Q: Please summarize your recommendations on residential rate design.

A: We make the following recommendations:

1) GSU's proposed flat per-KWH rate structure should be retained;
2) GSU's proposed concept of a summer-winter differential be retained;
3) GSU's proposed rate A2(experimental) be retained;
4) GSU's inclusion of the first 50 KWH/month in the customer charge be rejected, and this "mixed" customer charge be replaced by a "pure" customer charge, with GSU charging a per-KWH charge starting with the first, rather than the fifty-first, KWH/month;
5) that the "pure" monthly customer charge be no more than $4.34 per month, and that this "pure" monthly charge not vary between winter and summer;
6) that lost revenues to GSU resulting from the 16.3% reduction in the customer charge be spread evenly out over residential

consumption on a flat per-KWH basis (this assumes that all adjustments to revenue allocations to the residential customer class recommended in §II of this testimony have been completed); and

7) that the per-KWH summer-winter differential be retained at approximately its current size of 22.8% rather than GSU's proposed 16.0%.

IV. Miscellaneous Points

A. Interruptible Rates

Q: Do you have any comments upon GSU's failure to file any proposed interruptible rates?

A: Yes. The Public Utility Regulatory Policies Act of 1978 (PURPA) (P.L. 95-617, 92 Stat. 3117-3173, codified at 16 U.S.CA. §§ 2601 *et seq.*) sets various criteria for state regulatory authorities in the exercise of their ratemaking powers. One of these criteria (PURPA §111 (d)(5), codified at 16 U.S.C.A. § 2621 (d)(5)) indicates the desirability of utilities' offering interruptible rates for industrial and commercial customers.

GSU's proposed rates filed in this case contain no true interruptible rate for either industrial or commercial customers. Vol. V of GSU Rate Filing, Section III, Schedules GS, LGS, LPS and LIS. This continues GSU's current policy of not offering such a rate. See GSU's rates, effective 11/3/79, Schedules GS, LGS, LPS, and LIS. It appears from GSU's Information Responses to ALL UPSET (Information Responses I-58 through I-62) that GSU has had no interruptible customers since 9/1/76, when its only then-interruptible customer was shifted from an interruptible contract to a firm rate.

Even without the existence of PURPA, we would strongly recommend that GSU develop and file with the P.U.C. an interruptible rate (or rates) for commercial and industrial customers. This is an especially important point for a utility in GSU's current situation, that is, with somewhat tight reserve margins and some degree of difficulty in raising capital fast enough to construct new capacity to serve load. Interruptible customers would provide the equivalent of installed capacity to GSU, in that each MW of connected interruptible load is a source of a MW of firm capacity in case of a generation shortage. [1]

Two additional points should be made here. First, GSU's Power Supply Curtailment Program (Vol. V of GSU Rate Filing, Section IV, Sheets 11-17) is not equivalent to an interruptible rate. GSU's Power Supply Curtailment Program provides for the orderly imposition by GSU of reductions in load in cases of excess loads over available capacity. The existence of such a load-shedding program does not negate the desirability of interruptible rates; rather, it highlights the economic attractiveness of letting individual industrial and commercial customers price the value to themselves of firm service and, accordingly, accept or reject an interruptible rate. Second, there may be a general feeling on GSU's part that, because many of GSU's industrial and commercial customers have relatively flat load curves and thus relatively high load factors, therefore few if any of these customers would opt for an interruptible rate. This may or may not be correct; however, in our view, it is largely irrelevant. GSU's customers know their own costs better than GSU, and GSU's customers know the value to themselves of firm and interruptible service better than GSU. Accordingly, even if

[1] In fact, customers with an especially great need for reliable service may choose to install backup capacity such as gas turbines or diesels, in light of GSU's current capacity problems. An interruptible rate would encourage such customers to periodically use such capacity to support at least part of their own load, <u>before</u> GSU needs to disconnect any customers.

GSU is quite certain for its own purposes that no such customers would accept an interruptible rate, the decision should be made by those with the best information: the industrial and commercial customers.

Q: In light of the foregoing discussion, do you have any recommendations with regard to interruptible rates?

A: Yes. We strongly recommend that, regardless of the outcome of this rate case, the P.U.C. order G.S.U. to file proposed optional interruptible rates for industrial and commercial customers. The potential benefits are large, and the cost of designing and offering such a rate (even if no customer adopts it) are minimal. We believe that the design of such rates is a straight-forward task, and could be performed by GSU in time to file the interruptible rate simultaneously with the other rates that stem from the decision in this case.

B. Controlled Water Heating and Controlled Space Conditioning Rate

Q: Do you have any comments upon GSU's lack of controlled water heating and controlled space conditioning rates?

A: Yes. GSU has proposed a controlled water heating rate (Vol. V of GSU Rate Filing, Section III, Schedule WHS) which is closed to new business. This WHS rate was originally only available to GS and LGS customers, and has been closed to new business for some time. GSU does not have a controlled space conditioning rate for either commercial or industrial customers. See Vol. V of GSU Rate Filing, Section III, Schedule SCS.

The net result of schedules WHS and SCS for the availability to GSU customers, old and new, of controlled water heating and space conditioning rate is thus as follows:

Availability of Controlled Rates

	Controlled Water Heating Rates		Controlled Space Conditioning Rates	
Customer Class	New Customers	Old Customers	New Customers	Old Custom
Residential	No	No	No	No
Commercial	No	Yes	No	No
Industrial	No	No	No	No

Again, as discussed above in § IV (A) with respect to interruptible rates, PURPA requires utilities to offer to its customers such load control techniques as the state regulatory commission determines to be practicable, cost-effective, reliable, and useful to the utility. PURPA §§111 (d)(6), 115(c), codified at 16 U.S.C.A. §§ 2621 (d)(6), 2625(c). Again, even if PURPA did not exist, we would recommend that GSU expend much more substantial efforts in making controlled water heating and controlled space conditioning rates available to GSU customers.

Q: Have you done any studies to determine which, if any, additional controlled water heating or controlled space conditioning rates would be cost-effective load management tools for GSU?

A: No, we did not have the time, the resources, or the necessary data, to perform any such cost-benefit studies. We believe that such studies and initial determinations are best made by the utility in the first instance. However, we are reasonably certain based upon past experience that, if properly designed, controlled water heating and controlled space conditioning rates could provide an extremely inexpensive and effective load management tool for GSU.

Q: In light of the foregoing discussion, do you have any recommendations with respect to controlled water heating and controlled space conditioning rates?

A: Yes. We recommend that, regardless of the outcome of this case, the P.U.C. order GSU to design and file proposed controlled water heating and controlled space conditioning rates for all customer classes, for both old and new customers, or to explain in detail to the P.U.C. why such rates would not be cost-effective.[1] As the design of such rates might be a somewhat substantial task, we would not automatically recommend that GSU be required to file such rates simultaneously with whatever rates result from the P.U.C.'s order in this case. We would recommend that the P.U.C. order GSU to file such rates (or such detailed explanations why such rates would not be cost-effective) as soon as possible, and in no case more than 6 months after the P.U.C.'s final decision in this case.

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[1] We should make clear that we are not recommending that the present rate WHS be expanded. Certain features of rate WHS appear to contain promotional elements retained from earlier years. The discussion in this section assumes properly-designed, non-promotional rate proposals by GSU.

APPENDIX C:

Excerpts from, and Commentary upon, Pre-filed Direct Testimony of Mr. Maurice Brubaker in _Gulf States Utilities Company_, P.U.C.T. Docket No. 2677, on behalf of a group of LPS and LIS customers

APPENDIX C

This Appendix documents our assertion that one of the witnesses in GSU's last rate case (P.U.C.T. Docket No. 2677), Mr. Brubaker of Drazen-Brubaker & Associates, who filed pre-filed testimony on behalf of a group of LPS and LIS customers of GSU, appears to agree with the justifications for our main revenue allocation positions in this case.

First, Mr. Brubaker stated in P.U.C.T. 2677 that:

> If rates to one class of customer are established below the cost of serving that class, and the rates to other classes of customers are established at levels which exceed the cost of serving those classes of customers, changes in use will cause changes in revenues that are not in proportion to changes in the costs that result from those changes in use. On the other hand, if rates are set equal to cost for the various classes of customers, growth in use and changes in usage patterns will produce changes in utility revenues that are more in line with changes in the costs incurred by the utility as a result of growth or alteration of use patterns.
>
> Although it may be noted that cost specification cannot be absolutely precise and does not provide the only guide for designing rates, and that historical relationships between classes must also be recognized to avoid abrupt changes in rates, it is desirable to design rates so that the revenues from the various classes of customers approximate the costs incurred in serving the individual classes of customers. {Testimony of Mr. Brubaker, P.U.C.T. 2677, at 5-6.}

The first two sentences quoted above reduce to the classic justification for marginal-cost-based pricing. The changes in use Mr. Brubaker refers to will cause disproportionate changes in revenues in every case in which prices are not set at marginal costs. Although Mr. Brubaker never says so explicitly, this testimony is logically equivalent to a statement that marginal (not embedded) costs are the proper basis for prices, and that pricing electricity away from marginal costs is a cause of financial instability for utilities.

Second, Mr. Brubaker stated that:

> Conservation may be properly defined as the avoidance of inefficient, extravagant and uneconomical uses of electric energy. Since each individual consumer must decide for himself which uses are appropriate, it is essential that the consumer be faced with a price which reflects the cost of the service being provided. If rates are not based on costs, the choice made by the consumer will be distorted. Only when rates are based on costs can the proper choice be made, and the goals of conservation be supported. {Testimony of Mr. Brubaker, P.U.C.T. 2677, at 7.}

Again, although Mr. Brubaker never says so explicitly, this is logically a justification for marginal, not embedded, costs, as only marginal-cost-based prices can achieve the allocative efficiency goals Mr. Brubaker is discussing with reference to optimal conservation.

In both of the excerpts we have quoted, Mr. Brubaker also clearly indicates that rates should reflect the cost of the service provided to the customer. Therefore, if a customer's load curve is of the type that requires peaking capacity, the customer should pay for the peaking capacity, while if it justified new and existing baseload capacity, the customer should pay for that. In general, each customer should pay for a combination of capacity types which reflects the mix of benefits (reliability and cheap energy) that he receives from the capacity.

Third, in answer to a question as to whether some proportion of production power supply investment is not really energy-related rather than demand-related, Mr. Brubaker stated:

> With respect to this argument, it should be noted that the economic choice between a base load plant and a peaking plant must consider both capital costs and operating costs, and therefore is a function of average total costs. The capital cost of peaking plants is lower than the capital cost of base load plants, but the operating costs of peaking plants are higher than the operating costs of base load plants. Moreover, when the hours of use are considered, the fixed cost per kilowatthour for the base load plant is usually less than the fixed cost per kilowatthour for the peaking plant. Of course, since the fuel costs of base load plants are lower than the fuel costs of peaking plants, the overall cost per kilowatthour for base load plants is also less than the overall cost per kilowatthour for peaking plants.
>
> It is necessary, therefore, to look at both capital costs and operating costs in light of the expected capacity factor of the plant. The fact that base load plants have lower fuel costs than peaking plants does not mean that the investment in base load plants is made strictly to achieve lower fuel costs. Investment in a base load plant would be made to achieve lower total costs, of which fixed costs and fuel costs are the primary ingredients.
> (Testimony of Mr. Brubaker, P.U.C.T. 2677, at 13.)

Mr. Brubaker acknowledges, then, that the greater capital cost of the baseload plant is incurred because the greater hours use (i.e., energy) justifies the investment. He is correct that lower fuel costs are not a sufficient justification for building baseload facilities; the savings in fuel cost must be substantial enough to outweigh the extreme capital cost.

Having agreed, in effect, that base-load plants are built due to energy sales, rather than peak, Mr. Brubaker then asserts that costs which are fixed in the short term are not energy related:

> Given an existing system, the capital costs do not vary with the number of kilowatthours generated, but are fixed and therefore are properly related to system demands, not to kilowatthours sold. These costs are fixed in that the necessity of earning a return on the investment, recovering the capital cost (depreciation), and operating the property are a function of the existence of the property and not a function of the number of kilowatthours sold. If sales volumes change, these fixed costs are not affected, but continue to be incurred, making them fixed or demand-related in nature.
> {Testimony of Mr. Brubaker, P.U.C.T. 2677, at 14.}

Of course, the capital costs of a utility in 1980 do not vary with actual energy output in 1980. Neither, however, do they vary with actual demand in 1980. Capital cost in 1980 is determined by the expectation in previous years of 1980 peak demand, 1980 sales, 1980 load shape, and in the case of CWIP particularly, the load curve in years after 1980. Some expenses were incurred to meet peak economically, others to supply baseload energy economically, and the fact that those sums were committed many years previously does not change the reason for the commitment, nor the role served by the facilities. Therefore, this particular argument is a non-sequitur; there is no necessary equivalence between "fixed" costs and "demand-related" costs.

> In my opinion it is not proper to classify a portion of the fixed costs related to production on the basis of energy. However, if an attempt were made to increase the allocation of investment to one group of customers, on the theory that those customers benefit more than others from the lower energy costs that result from the operation of a base load plant as opposed to a peaking plant, the analysis should be carried to its logical conclusion, and the energy costs allocated to that group of customers, who are forced to bear the higher capital costs, should be reduced to recognize these lower operating costs which result from the higher capital costs of the base load plants.
> {Testimony of Mr. Brubaker, P.U.C.T. 2677, at 14.}

We agree with this last statement. The benefits of cheap energy from baseload plants is distributed in proportion to energy consumed, and we are simply suggesting that the costs be distributed similarly, so that both costs and benefits are borne by the same customers to the same extent.

We do not mean to say in this Appendix that Mr. Brubaker agrees with our revenue allocation conclusions. Quite to the contrary, it should be made clear that Mr. Brubaker almost certainly disagrees with all of our major revenue allocation conclusions. However, it is correct to conclude that Mr. Brubaker has testified to the subsidiary facts which properly lead to the following conclusions:

(1) marginal-cost-based prices and rates may maximize allocative efficiency and promote the "optimal" amount of conservation whereas embedded-cost-based rates can not; and

(2) the reasons which cause utilities to build base-load generating facilities, which are more-capital-intensive and more-fuel-efficient than peaking capacity, demonstrate the logic of assigning a portion of production power supply investments and expenses as energy-related costs.

Appendix D

ELCF Calculations

Appendix D

Table D-1 tabulates sources of estimates for ELCR's for units with EFOR $\geq$ 10%. The values vary with the composition of the rest of the system (excluding the unit for which ELCR is to be estimated), but the pattern is clear. Units of 5-10% of system capacity and with 15-25% EFOR have ELCR's on the order of .45 to .55.

Since GSU's current capacity is 5554 MW, a 550 MW unit represents 9.90% of current capacity. When Nelson 6 is added, it will represent 8.63% of GSU's other capacity at that time.

As Table D-2 demonstrates, the capacity factors of large plants are consistent with the 15-25% EFOR range.

A small unit imposes no size penalty for its outages and its EFOR can be thought of as a deterministic constant derating. The small maintenance requirements can be scheduled off peak. Therefore, a small gas turbine with a 10% EFOR has an ELCR of .9. Therefore, the effective load carrying factor (ELCF), by which MW 's of large plant capacity may be conve to MW's of peakers, is on the order of .5 ÷ .9 = .55. We give the large plants the benefit of the doubt, and use .6 for our ELCF for 550 MW units.

Study[1]	EFOR [2] %	Plant Size as % of Previous System Capacity	ELCR[3]
Kahn	10	4.89	.691
	12	"	.594
	15	"	.538
	19.7	"	.475
	10	9.78	.449
	10	12.23	.366
	15	2.53	.606
Billington,	about 23 [4]	17.65	.379
et al.	"	15.00	.435
	"	13.04	.468
	"	11.54	.535
	"	10.34	.548
NEPOOL	18-26.4	5.40	.537
		4.39- 5.14	.526 -.561

Table D-1: Sources of ELCR estimates

Notes (1) See bibliography

2) Equivalent Forced Outage Rate

3) Effective Load Carrying Ratio = MW load carried ÷ MW capacity

4) Billington, et. al. , actually model partial forced outages, which increase ELCR

Study	Plant Type	Size	Capacity Factor
Easterling/ NRC(2)	Supercritical Coal	400+	56.6%
	Nuclear, BWR	940	51.4
Perl./ NERA	Supercritical Coal	600	68.8
	Nuclear PWR	900	64.9
EPRI (3)	Coal	> 600	62.2 (1)
		600-700	63.7 (1)
	Oil	600-700	60.0 (1)
		> 600	64.5(1)
	Gas	700-800	71.8(1)
	Nuclear, BWR-3	545-794	60.2(1)

Table D-2: Capacity Factor Estimates

Notes

(1) Equivalent Availability Factor -corrected for load following

(2) Econometric projections, based on data through 1979

(3) Estimated actuals, through 1977

Appendix E

Energy-Related and Reliability-Related

Allocation Calculations

Appendix E

We will assign all units with in-service dates before 1/1/63 entirely to reliability. These units include:

Louisiana	7,8,9
Neches	3,4,5,6,7,8
Nelson	1,2,3
Willow Glen	1
Sabine	1,2

The calculation of capital costs for the peaking equivalent of each of the existing units is shown in Table E-1.

Unit		COD	HW(COD)	Capacity in MW	ELCF	Equivalent Cost	Actual Cost	Equivalent as % of Actual
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Lewis Creek	1	12/70	139	265	.871	73.92	99.54	74.3
	2	5/71	146	265	.871	73.92	99.54	78.0
Nelson	4	7/70	136	500	.730	60.62	109.45	55.4
Sabine	3	12/66	111	430	.772	52.32	67.49	77.5
	4	8/74	196	568	.700	83.77	110.00	76.2
	5	12/79	303	480	.742	137.27	285.65	48.1
Willow Glen	2	1/64	102	198	.911	56.73	87.53	64.8
	3	12/68	120	500	.730	53.49	98.52	54.3
	4	7/73	163	500	.730	72.65	151.52	47.9
	5	7/76	243	550	.700	103.86	175.47	59.2

Table E-1: Calculation of Peaking Equivalent Cost for Existing GSU Units in Service After 1/1/63

Notes:
(1) Commercial Operation Date.
(2) Handy-Whitman index nearest COD, 1957-1959=100.
(3) in MW.
(4) ELCF=1.03-.0006 (Capacity); see text.
(5) $\{\$233 \div (1.08)^3\} \div \{303 \text{x} HW(COD) \text{x } ELCF\}$, in \$/kw; see text.
(6) From Info. Resp. V-1; \$/kw
(7) ((5)÷(6))x100.

The operating expenses (excluding fuel) for peaking units in 1979 were estimated from data on 11 plants in New England, as shown in Table E-2, and may be compared to the non-fuel O&M for GSU's plants in Table E-3. All data is from FERC-1, p. 432, or equivalent.

Table E-4 weights MW capacities by ELCF estimates to determine the equivalent O&M (excluding fuel) cost of a gas turbine system with equivalent load carrying capability.

Table E-5 attributes the original cost of GSU's existing generating units to reliability-related and evergy-related portions by using the reliability-related percentages developed in Table E-1.

Ideally, one would want to weight each plant account/year vintage/ generating unit combination separately, and one would also want to do separate calculations for depreciation expense, accumulated reserve for depreciation, accumulated reserve for F.I.T., property taxes, etc. However, the requisite data for this highly disaggregated method of calculation was not available and might be expensive to generate. We would recommend in the future that GSU apply the reliability-energy percentage ratios which we calculate in Table E-1, column (7), to each unit's contribution to each account. This would be a compromise in terms of computational accuracy and complexity between our methodology here and the ideal calculation described in this paragraph. In our methodology here, all calculations are based on original capital cost, because we do not have unit-by-unit breakdowns by account and vintage.

Utility and System	Plant	$Units	Capacity in MW	1979 O&M excluding fuel ($/MW)
Montaup Electric (Eastern Utilities Associates)	Somerset	2	48	313
Boston Edison	L Street	1	18	2866
	Edgar	2	24	0
	Mystic	1	12	682
	Framingham	3	36	644
	West Medway	3	171	2925
Western Massachusetts Electric (Northeast Utilities)	East Springfield	1	16	1447
	West Springfield	1	22	964
	Doreen	1	18.6	2473
	Woodland Road	1	18.6	2258
	Silver Lake	1	56.6	1079
			Average	1423

Table E-2: O&M Expense (excluding fuel) for Some New England Peaking Plants

Plant	Capacity in MW	1979 O&M excluding fuel in $	$ 1979 O&M excluding fuel per MW
Neches	427	3,577,755	8379
Sabine(1)	1458	8,818,891	6049
Lewis Creek	530	2,883,993	5441
Nelson	846	6,794,476	8031
Willow Glen	1894	14,626,149	7722
Louisiana #2	154	1,701,956	11052
Louisiana #1	168	3,629,778	21606
	Total	42,032,998	

Table E-3: O&M Expense (excluding fuel) for GSU Plants

Notes: (1) Excluding 480MW from Sabine 5.

Plant		Capacity in MW	ELCF	Equivalent Capacity in MW
Lewis Creek	1	265	0.871	231
	2	265	0.871	231
Louisiana	7	44	1.000	44
	8	44	1.000	44
	9	66	0.990	65
Neches	3	27	1.000	27
	4	46	1.000	46
	5	66	0.990	65
	6	66	0.990	65
	7	111	0.963	107
	8	111	0.963	107
Nelson	1	100	0.970	97
	2	100	0.970	97
	3	146	0.942	138
	4	500	0.730	365
Sabine	1	230	0.892	205
	2	230	0.892	205
	3	430	0.772 (1)	332
	4	500	0.700 (1)	350
Willow Glen	1	146	0.942	138
	2	198	0.911	180
	3	500	0.730	365
	4	500	0.730	365
	5	550	0.700	385

Total 4254 MW

X 1423 $/MW (from Table E-2)

$6,053,442

Table E-4: Calculation of Annual O&M, Excluding Fuel, of Peaking System Equivalent to GSU Generation

Notes: (1) Based on 568MW rating

Plant		$ M Original Cost	% Attributable to Reliability	$M Reliability Cost	$ M Energy Cost
(1)		(2)	(3)	(4)	(5)
Lewis Creek	1	26.4	74.3	19.6	6.8
	2	26.4	78.0	20.6	5.8
Louisiana	7	4.7	100	4.7	0
	8	4.7	100	4.7	0
	9	6.6	100	6.6	0
Neches	1	2.6	100	2.6	0
	2	4.3	100	4.3	0
	3	6.3	100	6.3	0
	4	6.1	100	6.1	0
Nelson	1	13.4	100	13.4	0
	2	13.4	100	13.4	0
	3	15.5	100	15.5	0
	4	54.7	55.4	30.3	24.4
Sabine	1	26.0	100	26.0	0
	2	18.2	100	18.2	0
	3	29.0	77.5	22.5	6.5
	4	62.5	76.2	47.6	14.9
	5	137.1	48.1	66.0	71.1
Willow Glen	1	22.4	100	22.4	0
	2	12.8	64.8	8.3	4.5
	3	49.3	54.3	26.7	22.6
	4	75.8	47.9	36.3	39.5
	5	96.5	59.2	57.1	39.4
Total $		$714.7		$479.2	$235.5
Total %		100.0%		67.0%	33.0%

Table E-5: Calculation of Percentage of GSU On-Line Generating Plant that is Energy-Related and Reliability-Related

Notes:

(1) Name of Unit

(2) From Information Response V-1 of GSU to ALL UPSET

(3) From Table E-1, column (7)

(4) = (2)x(3)

(5) = (2)-(4)

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