133 Ex AG-VIII 2

COMMONWEALTH OF MASSACHUSETTS

BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

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| **Massachusetts Electric Company** | **Docket DPU-95-40** |

# DIRECT TESTIMONY OF

# PAUL CHERNICK

## ON BEHALF OF

## THE MASSACHUSETTS ATTORNEY GENERAL

Resource Insight, Inc.

June 9, 1995

## TABLE OF CONTENTS



## EXHIBITS

## I. Identification and Qualifications

**Q: Mr. Chernick, please state your name, occupation, and business address.**

A: I am Paul L. Chernick. I am president of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts.

**Q: Summarize your professional education and experience.**

A: I received a SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a SM degree from the 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, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a Utility Analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning: first as a Research Associate at Analysis and Inference, after 1986 as President of PLC, Inc., and since August 1990 in my current position at Resource Insight. In those capacities, I have advised a variety of clients on utility matters, including, among other things, the need for, cost of, and cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is attached as Exhibit AG-PLC-1.

**Q: Have you testified previously in utility proceedings?**

A: Yes. I have testified over one hundred times on utility issues before various regulatory, legislative, and judicial bodies, including numerous appearances before this Department. A detailed list of my previous testimony is contained in my resume.

**Q: Have you been involved in rate design and cost allocation?**

A: Yes. I have testified on rate design and cost allocation several times, before this Commission and elsewhere.

**Q: Have you been involved in utility planning in New England?**

A: Yes. I have been involved in the prospective and retrospective review of numerous resource plans and power plants, in a number of proceedings, since 1978. Most recently, I opposed excessive investments in generation resources in testimony on the Bucksport coal plant, and the purchase of Hydro Quebec power by the Vermont utilities. I also provided advice and support to clients in reviewing and opposing such projects as Newbay, Eastern Energy, and Silver City.

## II. Introduction

**Q: What is the purpose of your testimony?**

A: The major purpose of my testimony is to review the manner in which Massachusetts Electric Company (MECo) allocates costs to rate classes in its cost of service study (COSS). In particular, I deal in detail with the allocation of the costs of certain categories of New England Power Company (NEPCo) generation, and with the allocation of MECo's distribution equipment.

My testimony does not address the prudence or recovery of excess supply resource costs. Some of the information I present, however, may raise questions about the prudence of NEES's planning, or the usefulness of recently acquired resources.

**Q: Please summarize MECo's general approach in this rate case.**

A: MECo's approach tends to shift costs to residential and small commercial customers, and away from larger customers. This cost allocation result appears to be consistent with corporate policy of New England Electric Company (NEES), as indicated in NEES's March 1995 presentation to investment analysts (Exhibit AG-PLC-2), which touts allocation of a majority of the current rate case to residential customers, and 80% of the Narragansett rate increase to residential and small commercial customers as "designed to meet investors' and customers' needs."

**Q: Does this proceeding have any special significance, beyond the normal issues of equity and efficiency in cost allocation and rate design?**

A: Yes. The Department's decision in this case may establish precedents for restructuring, including the allocation of the costs of NEPCo generation that may be found to be stranded in a restructured market, the costs of power MECo may obtain in a more competitive market to serve its customers, and the costs of MECo distribution equipment. If MECo is separated from NEPCo, it will have greater freedom to allocate distribution costs to reflect the causation of those costs, without worrying about whether sales to particular classes are advantageous to its generation affiliate.

**Q: Please summarize your recommendations.**

A: First, the allocation of costs within MECo's cost-of-service study should be changed in the following ways:

- To properly reflect the contribution of various classes to NEES's current capacity excess, approximately $22 million in excess capacity costs should be reallocated from residential rates to Rate G-3/4.[1]
- To properly reflect the contribution of various classes to NEES's current surplus of baseload capacity, an additional $46.6 million in excess baseload supply costs should be reallocated from residential rates to Rate G-3/4, for a total $68.7 million reallocation of generation costs.
- Similar cost reallocations should occur from streetlighting ($0.7 million), Rate G-1 ($1.2 million) and Rate G-2 ($0.4 million) to Rate G-3/4.
- The costs of the distribution system, at the primary, transformer, and secondary levels, should be allocated to rate classes on the basis of diversified class peaks, or of diversified group loads by voltage level, rather than on undiversified customer peaks. This improvement will reduce cost allocations to residential and small commercial customers, and increase them to large customers with less intra-class diversity.
- Several expense items that MECo allocates in proportion to number of customers or bills should be allocated in ways that better reflect their causation. These costs include customer accounts, customer service, distribution overheads, and the power quality program. These

[1] Since MECo is proposing to merge Rates G-3 and G-4, I generally refer to Rate G-3/4.

improvements will reduce cost allocations to residential and small commercial customers.

- If the excess capacity and capitalized energy costs are not allocated to the riskier classes that caused them, the subsidy from NEPCo for reducing those risks with Service Extension Discounts should be allocated on basis of the production demand allocator (WHAM-D).
- The costs of the economic development discounts should be allocated to rate classes in proportion to base revenues, not rate base.

Second, the Commission should order MECo to undertake the following additional analyses to support improvements in future cost-of-service studies:

- Determination of the relative costs of serving various classes' loads, given historical and expected risks of variation in sales from forecast.
- Determination of the relative costs by class of service drops, considering the length of services, the average installed amperage, the mix of single-phase and three-phase services, and the mix of underground and overhead services.
- Identification of any secondary lines serving customers in Rate G-3/4.
- Differentiation of target generation reserve margins by rate class.
- Identification of transmission and distribution investments made to support the higher requirements for reliability and power quality of large customers.
- Classification as energy-related the portion of transformer and underground line costs resulting from energy loadings, including the effects of thermal limits imposed by long peaks and high load factors, and the effects of multiple overloads on equipment life.

- Development of an economic-development allocator, reflecting MECo costs, excluding meters, services, and customer-related costs, plus MECo's share of NEPCo's non-fuel costs.

Finally, the Commission should take the opportunity of the issues raised in this case to establish that the same considerations of cost causation that apply in the allocation of costs for retail ratemaking will apply to the allocation of the recovery (if any) of stranded costs that may result from future restructuring proceedings. Industrial customers are responsible for the bulk of the excess generation-resource costs, and should be expected to pay those costs, under any electric industry structure. The residential, small commercial, and streetlighting customers should not function as the guarantor of recovery for costs imposed by larger customers.

## III. Allocation of Bulk Power Supply Costs

**Q: How do NEPCo and MECo allocate generation costs between demand and energy?**

A: This allocation takes place in two steps: in NEPCo's rate design, with the four-way division of cost recovery between initial and tail blocks for demand and energy; and in MECo's allocation of those NEPCo costs by class.

The tail block of the NEPCo marginal-cost-based demand charge reflects the demand-related costs of peaking capacity, starting in 2002. The tail block of the energy charge includes levelized fuel costs and, starting in

2002, the capitalized energy from a new combined-cycle plant.[2] Excess costs are then recovered through the initial energy block and the initial block of the demand charge.

MECo then allocates the NEPCo charges by use of its Wholesale Hourly Allocation Method (WHAM), which produces allocators for demand (WHAM-D) and energy (WHAM-E). I reproduce those allocators, and other external allocators used by MECo, in Exhibit AG-PLC-18.

### *A. Reasons for Excess Current Costs*

**Q: Why are NEPCo's current rates for generation sales to MECo above market cost?**

A: The difference between NEPCo's generation rates to its affiliates and the market value of the power (such as for new sales to non-affiliates) can be attributed to four factors:

- Some of NEPCo's resources are simply too expensive, being priced above the long-term market value of the resource. NEPCo could have provided the same reliability, capability and energy from other sources at lower cost.
- Due to over-stated load forecasts, NEPCo acquired too much capacity (as measured in MW).
- At least in part for the same reasons, NEPCo acquired excessive baseload generation resources.

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[2]Due to levelization, only a portion of the costs of a new peaker is reflected in the tail-block demand charge, and only a portion of the capitalized-energy costs of a new combined-cycle plant are included in the tail-block energy charge.

- The short-term generation market in New England is depressed by a surplus of resources in the region.

The next three sections consider the various customer class's contribution to each of the first three problems. I do not include the fourth phenomenon; customers served under long-term firm arrangements would be expected to pay costs reflecting the long-term cost of new supplies, not the fluctuating short-term market-clearing price for spot purchases.

**Q: How do you propose to allocate the three categories of excess generation costs?**

A: Each cost should be allocated in proportion to the factors that caused it. The above-market costs should be allocated on energy or the equivalent. Excess capacity should be priced at the costs of contemporaneous peaking capacity, and allocated in proportion to the differences between projected peak loads (at the time commitments were undertaken) and actual current loads. Excess capitalized energy costs (net of equivalent peaking-capacity costs and any fuel savings) should similarly be allocated in proportion to the differences between projected and actual energy requirements.

### *B. Resources Priced above Long-term Market*

**Q: What current NEPCo resources are priced above the long-term market?**

A: The long-term market cost of power appears to be determined by the cost of a gas-fired combined-cycle plant, at about 4¢/kWh real-levelized or 5–6¢/kWh nominally levelized for a 30-year contract. The list of NEPCo resources above this cost level would probably include some Seabrook investment (although it is hard to tell from NEPCo's rate filings, due to the amortization of pre-1986 costs), Connecticut and Vermont Yankee, Millstone 3, the Hydro-Quebec Phase 2 interconnection, and some NUG purchases.[3]

Exhibit AG-PLC-3 lists the size and prices of NEPCo's purchases and sales. As shown on page 8, the Odgen-Haverhill, Resco-Saugus, and Signal-Millbury waste-to-energy projects are priced well above the market. Altresco and Pawtucket's prices per kWh are also very high, due to their low utilization; at baseload operation, they would cost somewhat less, about 6¢/kWh.

**Q: How should these above-market costs be allocated?**

A: All of these expensive resources were obtained primarily for energy purposes, and should be allocated on energy, or a similar factor. The high costs of the NUG contracts, Hydro-Quebec, and the newer nuclear units were justified by the fear of high oil prices. These resources were all clearly more expensive than peaking capacity on a $/kW basis, and were undertaken to provide large amounts of energy at low incremental running costs.

**Q: How are these costs allocated in MECo COSS?**

A: These costs are allocated with the WHAM-D and WHAM-E allocators, which are close to straight energy allocators, producing a reasonable result.

**Q: If NEPCo recovers any stranded investments (or obligations, in the case of contracts and nuclear decommissioning liabilities) associated with these above-market costs, how should those costs be allocated among customers leaving the NEPCo system?**

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[3]Non-baseload resources, such as the NU slice of system and the hydro NUGs, are difficult to evaluate without some production costing analysis.

A: The costs of uneconomic generation resources should be allocated as they are now, on the WHAM-D and WHAM-E allocators, or in proportion to energy usage.[4] The exiting customers should take with them their allocated share of the costs, to be paid at the time of departure, through a rider on the wheeling rate, or some other mechanism.

### *C. Excessive Capacity*

**Q: How much excess capacity is reflected in NEPCo's current rates?**

A: According to the 1994 IRP, NEPCo has 843 MW of excess for the summer of 1996, or about 20% of NEPCo's load.[5] The 1996 peak is the one included in the rate year. The 1996 capacity is greater than that in 1995, since 1996 includes the full 423 MW of repowered Manchester St. capacity, but the surplus is reduced by increases in loads since 1995.

**Q: What is this excess capacity composed of?**

A: The capacity that would not have been added, if NEES had anticipated the reductions in industrial load, and reductions in other classes' growth, includes 304 MW of incremental capacity at Manchester St.,[6] 230 MW from Ocean States Power, and 309 MW of capacity from other purchases, primarily from the non-utility generators listed in Exhibits AG-PLC-3 and AG-PLC-4.

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[4] This allocation rule does not apply to the costs of excess capacity or excess baseload resources, which are discussed below.

[5] I use 1996, as the calendar year most closely fitting the rate year for this case.

[6] This is computed as the 432 MW of the combined-cycle plant, minus the 128 MW claimed for the steam plant, from Table III.10.1 of the 1994 IRP.

**Q: What is the vintage of this excess?**

A: I determined the vintage of the excess by backing out specific units, starting with Manchester Street and moving back to various NUGs with progressively earlier in-service dates. Exhibit AG-PLC-4 lists the in-service dates of the major NUGs on NEPCo's system.[7] Altogether, the NUGs listed in Exhibit AG-PLC-4 comprise 537 MW.

**Q: Why did you only analyze additions since 1989?**

A: The current excess is due to the addition of capacity that has turned out to be unnecessary, which would normally be the last resources added. As shown in Exhibit AG-PLC-4, the capacity added since 1989 adds up to the 1996 excess.

The attribution of the excess to the period since 1989 is also supported by the history of NEPCo's loads. As shown in Exhibit AG-PLC-5, 1989 was the year in which NEES's loads stopped growing, leading to the present surplus.[8] Since current load levels exceed those prior to 1989, the excess is unlikely to result from earlier additions.

**Q: What is the cost of the excess capacity?**

A: Had NEPCo obtained excess peaking capacity, rather than the more expensive baseload capacity it has acquired, the 1995/96 cost would be the cost of the same amount of peaking capacity built in the same year as the actual resources. I therefore valued the demand-related portion of excess

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[7]If some of the excess were attributed to utility or smaller NUG purchases after 1989, the cost of the contemporaneous peaking capacity (and hence my computation of excess capacity costs) would rise.

[8] Table I.6.1 of the 1994 IRP shows a 1989 summer peak of 4,225 MW, which was slightly exceeded in 1992, but is not now expected to be passed again until 1998.

capacity at the cost of peaking capacity contemporaneous with the excess resources. The 304 MW of Manchester St. capacity is valued at the first-year cost of 304 MW of peaking capacity built in 1996, the 13 MW of MassPower is valued at the third-year cost of 1994 capacity, and so on.

I estimated the costs for 1996 in $/kW-year for peakers of various vintages, by deflating the peaking capacity cost estimate used in the NEPCo marginal cost study (WP BL-2, W-95 filing), and weighting by the MW of excess capacity of each vintage in Exhibit AG-PLC-6.

If there were any significant market value for off-system peaking capacity sales in the rate year, I would credit that value to this excess capacity. At this point, that value appears to be very small.[9]

### *D. Excessive Baseload Capitalized Energy Costs*

**Q: Is excess baseload capacity different from excess capacity?**

A: Yes, excess capacity and excess baseload capacity are independent. If the only resources that were underutilized were peaking units, such as combustion turbines, there would be no excess baseload. However, when plants that were built to be run a high percentage of the time, do not run at their full availability, there is excess baseload generation capacity, even if all of the capacity is needed at times of peak demand.

Baseload generating plant generally costs more to build than peaking resources, but less to operate. Only if the plant is fully utilized will this

[9] The NEPCo marginal cost study for Rate W-95 assumes a zero value for peaking capacity in the next several years. This assumption is also used in developing MECo's avoided costs used in evaluating DSM.

baseload investment premium—capitalized energy costs—be fully recuperated through lower running costs.

**Q: Does NEPCo have excess baseload capacity?**

A: Yes. Most of the excess capacity additions that I identified above are baseload plants. However, while their capacity is in excess of NEES's needs, their additional fixed costs might be justified by higher-priced fuel displaced by their energy production. In order to determine whether their energy generation capabilities are excessive, we must determine whether the energy that they supply could have been economically provided by other existing plants.

To determine whether adding Manchester Street station and the new NUGs resulted in uneconomical reduction in usage at NEPCo's older resources, I estimated the extent to which those resources are underutilized. In Exhibit AG-PLC-7, I estimate the total unused available generation from Brayton Point, Salem Harbor, Canal, and Wyman. The difference between the available generation and the projected actual generation from those plants in 1995, as projected by NEPCo in the W-95 wholesale rate case, is 4,394 GWh.[10]

**Q: How much of this energy capability is unused due to the newer resources?**

A: I compared the older plants' unused generation with the actual generation from the newer NUGs and Manchester Street. Exhibit AG-PLC-8 totals the

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[10] I did not have similar production costing results for 1996. In 1996, the excess would be reduced slightly by load growth, but increased by the operation of the first Manchester unit for a full year (rather than the three months reflected in the W-95 runs) and of the remainder of Manchester Street. Since the 1995 underutilized generation greatly exceeds the energy output of the resources that I classify as excess, these resources will still be excess in 1996.

generation from these newer plants, as projected in the system dispatch runs filed in the FERC W-95 NEPCo rate case. I limited my calculation to those resources whose generation is specified individually, which account for the 773 MW of the NEPCo's excess capacity.[11] As a result of the energy generation from these plants, NEPCo is able to run some of its own plants less.

I determined that all 3,352 GWh of the generation provided by the plants identified in Exhibit AG-PLC-8 could have been supplied by the older base-intermediate plants, which NEPCo projected to have unused available generation of about 4,393 GWh. Of course, any additional generation from Manchester St. in 1996 would also back down some combination of those same older plants and the NUGs.

**Q: Is it fair to assume that these plants could operate close to their full EAF?**

A: Yes. NEPCo's energy-limited hydro-electric plants and the Bear Swamp pumped-storage plant provide enough capacity in high-load hours so that the load that must be met by the thermal plants (fossil and nuclear) in those hours is essentially the same as the loads in the low-load hours.[12] In addition, pumping up the Bear Swamp plant off-peak raises those loads. As a result, the load that NEPCo's thermal units must meet is essentially flat.

[11] NEPCo's production costing runs do not distinguish between several of the smaller NUGs.

[12] The same would be true for the energy-limited Hydro-Quebec contract, although this is dispatched through NEPOOL, rather than NEPCo's own-load dispatch.

**Q: Do you have any confirmation from NEES that its recent baseload additions would back down primarily low-cost generation at baseload and intermediate steam units?**

A: Yes. First, NEPCo's W-95 production costing runs show the new combined-cycle plants operating at fairly low capacity factors, indicating that there is no more-expensive generation for them to back out in many hours. Second, as shown in Exhibit AG-PLC-9, NEES recognized as far back as 1991 that Manchester Street would primarily displace generation from such low-cost plants as Brayton, Salem, Canal 1, and the then-committed NUGs.

**Q: How much does this excess baseload capacity cost?**

A: I estimate that the excess generation capacity will cost about $182 million in 1996.

I calculated this value by estimating the capitalized energy costs of the excess NUG purchases and Manchester Street, and netting out the fuel savings due to those NUGs with lower operating costs than the generation they back out. These calculations are shown in Exhibit AG-PLC-10.

To calculate the capitalized energy costs, I added up the 1996 fixed costs of the NUGs ($163 million) and Manchester St. ($106 million). From this total, I subtracted out the fixed costs that would have been incurred had these plants been built only to meet demand (as simple-cycle gas turbines).[13]

Next, I subtracted out the savings in operating costs that results from running the new NUGs instead of the older plants. According to NEPCo's estimates of dispatch prices, only Pawtucket and Altresco actually offer

[13] These costs are a subset of the excess capacity costs calculated in Exhibit AG-PLC-6, and will be allocated with other excess capacity costs.

running costs significantly lower than the older plants, so these are the only plants for which I have computed fuel savings.[14]

### *E. Allocation of Excess Costs by Class*

**Q: How should the excess costs be allocated to rate classes?**

A: The excess capacity costs should be allocated in proportion to the overforecasting of the coincident peak loads that resulted in NEPCo obtaining too much total capacity. The excess capitalized energy costs should be allocated in proportion to the overforecasting of class energy requirements that resulted in NEPCo obtaining too much baseload capacity.

#### *1. Energy forecasting errors*

**Q: Have you estimated each class's portion of the excessive projections of energy requirements that led to the excess capitalized-energy costs?**

A: Yes. I estimated each class's portion of the over-projection of 1994 and 1995 sales in the forecasts that NEES and MECo prepared in 1987-91.[15] The NEES forecasts are shown in Table 1 of Exhibit AG-PLC-11, while the MECo forecasts are shown in Table 2. I used the forecasts from 1987–1991 because

- pre-1987 sales forecasts did not overestimate total sales in 1994 and 1995;[16]

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[14] See page 2 of Exhibit AG-PLC-7, an excerpt from the workpapers of NEPCo witness Paradise in the W-95 rate case before FERC.

[15] Since the 1995 actual sales figures are not yet available, I used the 1994 sales forecasts for 1995 as if they were actuals.

[16] The industrial forecasts were overstated, but residential and commercial forecasts were understated; if NEES had built to these forecasts, there would have been no excess capacity.

- the excess capacity and capitalized energy costs are associated with commitments made in 1987–1991; and
- the post-1991 forecast errors are very small, and would not have resulted in the current excess.[17]

Tables 1 and 3 of Exhibit AG-PLC-12 show the GWH errors by class and for the total company for NEES and MECo, while Tables 2 and 4 show the errors as percentages of actual sales.

**Q: Which years' forecasts contributed to the over-supply of energy resources in 1994 and 1995?**

A: The forecasts of total 1994 and 1995 sales, on either the NEES or MECo level, were first overprojected in 1987, peaked in 1989 and 1990, and declined dramatically in 1991.[18] Based on this pattern of errors, the over-supply of baseload generation could be attributed to errors in

- 1987–1989, when the errors increased every year, encouraging NEPCo to obtain ever greater amounts of energy supply that are now excess;
- 1989–1990, when the errors were greatest; or
- 1990-91, when the continuing errors prevented NEPCo from reducing its over-supply through renegotiation, off-system sales, and the delay or cancellation of Manchester St. repowering.

**Q: Which classes were most responsible for the excess capitalized energy costs?**

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[17] The only post-1991 forecast I was able to find was from the 1992 IRP. The more accurate 1992 forecasts did not result in reversal of the earlier commitments to the capacity that is now excess, either because NEES was unable to amend contracts and sell capacity, or because NEES failed to exercise available options.

[18] MECo sales forecasts are not available for all years.

A: Exhibit AG-PLC-13 presents the average sales-forecasting errors over various time periods for each class and the total system, for both NEES and MECo.[19] I computed averages for the forecast errors for 1994, the forecasts errors for 1995, and averaged the 1994 and 1995 results. The same tables also show the ratio of each class's percentage error to the system average error. For all the relevant periods, the industrial sales forecasts were overstated more than the system average; the industrial error ranged from 1.51 times the average error for 1989-90 NEES forecasts for 1995, to 3.76 times for 1987-91 MECo forecasts for 1994. The residential errors were always smaller than the system average error, and often actually helped offset the industrial errors, especially in the MECo system. Commercial class errors range widely, from 0.79 to 1.64 times the system average.[20]

**Q: Which average did you use in developing an allocator for the excess capitalized energy cost?**

A: I previously discussed the reasons for believing that the 1987–91 forecasts were potentially relevant. The results for 1994 are attractive since they rely on actual sales data, while the results for 1995 are appealing because they reflect a period overlapping the rate year. The MECo results are relevant, since the Department is setting rates for MECo, but the NEES results incorporate more forecasting data, and reflect the total loads that contributed to the excess capitalized energy costs that are being allocated in this case.

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[19] Due to the missing forecast data, the MECo averages have less data than the NEES averages.

[20] I have assumed that streetlighting did not contribute to excess generation resources.

To incorporate all of these considerations, I used the broadest reasonable measure of the over-projections, a three-way average of the ratios of class error to total error. For each of the classes, I averaged the class error ratios of (1) the forecasts prepared in the five years 1987-91, (2) for 1994 and 1995, and (3) for NEES and MECo. The forecast-error ratios I used in subsequent computations are highlighted in Exhibit AG-PLC-14. The residential class contributed nothing to the error (and actually mitigated the over-estimates for other classes), while the commercial class was over-forecasted by about as much as the system as a whole, and the industrial class by twice the average.

2. *Allocation of excess costs*

**Q: What share of the excess capitalized energy cost you identified above does NEPCo charge to MECo?**

A: MECo pays 73.0% of NEPCo's energy costs, 72.5% of NEPCo's demand costs, and 72.8% of NEPCo's total base-rate costs, or $133 million of the total $182 million in excess capitalized energy cost identified above.[21]

**Q: How should these excess capitalized energy costs be allocated to rate classes?**

A: These costs should be allocated to each rate class in proportion to the class's GWH forecasting error. I estimated each class's share of the energy forecasting error by multiplying the class's share of test-year energy usage (from Exhibit AG-PLC-27) by the averaged ratio of the class error to the system error over several years (as derived in Exhibit AG-PLC-13), and then

[21] Rate W-95 filing, Statement BG, Period II, p. 4-5.

normalizing the total to 100%. I treated the negative error in the residential forecasts as equivalent to zero error. This computation is shown in Exhibit AG-PLC-14.[22]

**Q: What share of the excess capacity cost you identified above does NEPCo charge to MECo?**

A: MECo pays approximately 72.8% or $63 million of the total $86 million in excess capacity costs identified above.

**Q: How should these excess capacity costs be allocated to rate classes?**

A: These costs should be allocated to each rate class in proportion to the class's MW forecasting error. Since NEES does not publish its forecasts of class peaks, I assumed the percentage errors in forecasting class peaks were the same as the percentage errors in forecasting class sales. I estimated each class's share of the demand forecasting error by multiplying the class's share of test-year contribution to coincident peak (from Exhibit AG-PLC-27) by the ratio of the class error to the system error, and then normalizing the total to 100%. This computation is shown in Exhibit AG-PLC-15. While this computation parallels my allocation of excess capitalized energy costs, industrial loads represent a smaller part of the peak load, and hence a smaller part of the errors, due to their higher load factors.

**Q: How much do these corrections affect MECo's cost allocations?**

A: Exhibit AG-PLC-16 shows the differences between MECo's proposal and my recommendation for the class allocations for excess capacity and

[22] As noted above, the allocation of the commercial and industrial customer class excess capacity between the general-services rate classes is an approximation, subject to better data on the overlap between rate classes and customer classes.

capitalized energy costs. MECo allocates the excess costs on the WHAM-D and WHAM-E allocators, just as it does required supply resource costs.[23] Allocating these excess costs to the classes that imposed them reduces the residential cost allocation by $69 million. This is more than the total $56 million rate increase MECo proposes for the residential class.

### *F. Quantifying the Risk of Forecast Uncertainty*

**Q: Your analyses above estimate the current level of excess costs that resulted from the historical decline in anticipated sales to industrial customers. Are these unanticipated changes in industrial load unusual?**

A: No. Energy sales to industrial customers are generally acknowledged to be uncertain, risky, and volatile, varying with the national or international condition of each industry, as well as the competitive position of the local firms within the industry. This widely-recognized phenomenon is discussed and quantified by Brennan (1980), Rohr and Stumpp (1982), and Spencer and Maddigan (1983).[24]

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[23] I assumed for this computation that the excess costs were recovered through the NEPCo demand charge and allocated with the WHAM-D. If a portion of the excess costs are allocated by the WHAM-E (as seems likely, since some NUG costs and return on Manchester St. are recovered through the energy charge), additional costs should be shifted out of the residential class, but less would be shifted from small commercial customers. The WHAM-D and WHAM-E allocators are essentially identical for Rate G-3/4, as shown in Exhibit AG-PLC-18.

[24] Brennan, Joseph F., "Rate of Return Differential by Class—A New Dimension to Cost of Service," *Public Utilities Fortnightly,* April 10, 1980: 11-16; Maddigan, Ruth J. and Charles W. Spencer, "On Customer Class Rate of Return Differentials," *Public Utilities Fortnightly,* December 8, 1983: 19-25; Rohr, Robert J., and Mark S. Stumpp, "Differential Class Rates of Return: Some Theoretical & Empirical Results," in *Award Papers in Public Utility Economic and Regulation,* 151-177 (Michigan: Institute of Public Utilities, 1982). Some of these studies conclude that industrial sales risk does not contribute much to risks to *shareholders,* probably

**Q: Have you attempted to quantify the difference in forecasting risk for the industrial, commercial and residential loads of NEES?**

A: Yes. Exhibit AG-PLC-17 shows NEES's average percentage forecasting errors by class for three to six years into the future, forecasting for sales in the years 1991–94.[25] I selected this range of forecasts to cover the period in which resource needs are identified and commitments are made. The accuracy of forecasts over this "planning window" will largely determine whether the utility will underbuild or overbuild its system.

For each forecast year, I computed the average error in the forecasts NEES prepared three to six years earlier. I used a simple average of these errors, to reflect the fact that over- and under-projections in the planning window will tend to offset one another. I then averaged the absolute value of the errors across years.

The absolute errors for the four forecast years varied from less than 1% to 10% of actual sales for residential sales, from 2% to 10% for commercial sales, and from 5% to 15% for industrial sales. The average of the absolute errors was 3.6% for residential sales, 5.6% for commercial sales, and 10.8% for industrial sales. The industrial error is approximately twice the commercial error, and three times the residential error.[26]

**Q: Are industrial customers inherently more expensive to serve, due to the risk in their load?**

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because, like NEES currently, utilities are usually able to increase rates to cover the multi-year shortfalls in industrial sales.

[25]I used NEES forecasts because I have not been able to find a 1989 MECo forecast.

[26] The ratios are even more striking for errors computed as a percentage of forecast.

A: Yes. The surge of industrial load growth resulted in the uneconomic operation of existing generation in the late 1980s, the rushed acquisition of supply resources in the same period, and the resulting expensive surplus in the 1990s. Recognizing their greater risk, a competitive market would demand a higher return on investment and hence charge more for the commitment of fixed resources for industrial customers than for residential and commercial load.[27]

**Q: Have you estimated the extra cost of industrial risk?**

A: Yes. I have interpolated the cost of industrial risk from NEES's estimate of the value of a five-year contract commitment. MECo (compensated by NEPCo) proposes to offer a 12.5% service extension discount (SED) in base rates for very large industrials that use at least 100 GWH annually and contract to take all of their electricity purchases from MECo for five years. These contracts would reduce, but would not eliminate, NEES's risks of serving the industrial loads.[28]

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[27] The additional charges might include reservation fees, deposits, or take-or-pay contracts.

[28]Under the current rates, while the customer is not allowed to "take from another supplier or cogenerate" at the current location, the level of load is not guaranteed, since "they can drop [load], they can actually leave our service territory." Lawrence J. Reilly testifying for MECo, DPU 93-194, November 22, 1993, Tr. at 28. Little of NEES's current excess supply is due to customers cogenerating or switching suppliers in place, so these discounts were being offered in exchange for a rather modest reduction in risk. MECo is now apparently seeking a firm take-or-pay commitment.

Attempts to require customers to take power they do not want, cannot use, and cannot afford are fraught with difficulty. Minnesota Power signed take-or-pay contracts with a number of large industrials about 1980, which largely turned out to be unenforceable within a few years, due to bankruptcy or financial distress.

**Q: How did MECo justify these discounts?**

A: MECo has justified these discounts on the grounds that they reflect the reduction in the risks of serving G-3 loads under contract, rather than standard tariffs. Lawrence J. Reilly, testifying for MECo in DPU 93-194 (November 22, 1993), made this point several times:

> [T]he customers are all getting the benefits of the commitments that the [customers taking the SED] have made, [that] are not free to leave the system and leave stranded costs for the other remaining G-3 customers to absorb. Tr. at 18.

> We're optimistic that, in the event that we know better what our future load is going to be from our G-3, or large commercial/industrial customers, that that will ultimately results in savings on the power-supply side, where New England Power Company will better match its acquisition of resources to its future load of the G-3 class. Tr. at 19

> [I]f we can realize some efficiency savings in terms of our power-supply procurement, that we would pass those savings on to the retail company. Tr. at 20

> We believe [the SED] will provide benefits to us in terms of knowing better what our future loads are going to be. It also provides an opportunity for us to reflect lower costs...to our customers right away. Tr. at 22.

> New England Power Company would step up and reflect the lower power-supply costs that it experienced...in lower purchased-power bills to Mass. Electric. Tr. at 23-24.

> By these customers making long-term commitments, New England Power Company can better tally its power-supply commitments—it will know which customers are locked in or effectively planning to stay on the system for the next five years, and it can plan its power supply accordingly and produce savings, which could be passed through to the ultimate customers. Tr. at 31.

**Q: What is the implication of the service extension discount for residential ratepayers?**

A: The MECo residential class as a whole has sales of over 6,000 GWH, more than 60 times the sales required for a 12.5% contract discount for a single G-3 customer. If that discount is cost-based (even judgmentally) for a large reduction in industrial risk, the 66% reduction in forecasting risk between industrial and residential load estimated in Exhibit AG-PLC-17 would justify a residential discount (compared to industrial rates) of 66% × 12.5% = 8.3%. Since the SED contract does not eliminate forecasting risk, the equivalent residential discount should be even higher.

Alternatively, we can apply NEES's 12.5% discount to the share of residential load that is as secure as industrial load covered by a five-year contract. This share is at least 80%, and probably more than 90%, implying that residentials deserve a discount of 10%–11%.

**Q: If certain large customers are "at risk," should the COSS be designed to allocate a smaller share of costs to those customers?**

A: No. Lowering cost allocations to the riskiest customers would be perverse. These are the most expensive customers to serve, due to their risk. In a competitive generation market, these customers would pay higher rates, to reflect the higher expected rate of return required to support investments whose return is particularly risky, as well as the greater probability of stranded investment.[29]

Short-term cost and elasticity considerations may prevent the Department from raising rates to existing high-risk customers to reflect their risk. Nonetheless, the cost allocation should recognize this differential in

[29]These considerations apply to the distribution system, as well as generation and transmission.

risk, so the Department and the public know how much the residential, small commercial, and streetlighting customers are subsidizing the risky customers. The risk of these competitive customers should also be taken into account in determining the minimum acceptable rate for new high-risk customers, especially those for who require long-term capital commitments.

### *G. Generation-related Costs of Serving Large-customer Loads*

**Q: Are there any other costs incorporated in NEPCo's rates that are driven by the loads of large customers, but are not allocated to those customers?**

A: Yes. Industrial and commercial customers generally demand a higher level of bulk power reliability than do residential customers, for two reasons. First, regardless of generation reliability, residentials do not receive very high delivered reliability, due to distribution outages (often much longer than rolling brownouts or blackouts for generation). Industrial and large commercial customers usually have higher reliability, since major facilities are located closer to the load centers they create, and they are often served off of networks, loops, and other redundant systems. Large-customer service reliability is therefore much more sensitive to generation reliability than is that of residential customers.

Second, the costs of short outages to residentials are generally lower than those for commercial and industrial customers, who face lost production, lost sales, damaged equipment and materials. Commercial and industrial electronic equipment is also more sensitive than most residential to power quality, so brownouts can also be very costly.

Similar concerns arise for transmission reliability, particularly in terms of short outages or voltage fluctuations, which are often just a nuisance for residential customers, but can be very expensive for larger customers.

**Q: What costs are associated with these demands for higher reliability and power quality from large customers?**

A: NEPOOL and NEPCo are likely to aim for higher bulk power reliability levels, and to invest in equipment to speed recovery from generation and transmission failure, and provide alternative transmission paths and faster switching of loads in response to contingencies.

**Q: Has MECo provided any information demonstrating that the power quality concerns you discuss are primarily a problem for the larger customer classes?**

A: Yes. IR DPU 2-17 describes a program for helping customers identify and deal with power quality problems. Of the 178 MECo customers to have participated in this program, only three have residential rate codes, and two of those have corporate names, suggesting that they are multi-family developments.

## IV. Allocation of MECo Distribution Costs

**Q: How does MECo allocate distribution costs to rate classes?**

A: MECo allocates substations, primary lines, transformers, and secondary lines on the sum of customer demands at various voltage levels.[30] Services are

[30]Since property records are not normally maintained by voltage level within the distribution functions, MECo also had to sub-functionalize conductors, poles, conduit, and the like between primary and secondary. I have not reviewed that functionalization analysis.

allocated on a weighted customer allocator. These allocators are summarized in Exhibit AG-PLC-18.

**Q: Are there any problems with MECo's allocation of its costs?**

A: Yes.

- MECo does not account for any extra costs required by the service needs of large customers, including increased distribution reliability, power quality, and reactive power.
- MECo does not account for the effects of energy usage and long-hours non-residential loads on the ratings and equipment sizing of transformers, substations, and lines.
- MECo overstates small-customer contributions to load on all level of the distribution system, by allocating costs on undiversified customer loads.
- MECo appears to understate differences in customer-related costs (e.g., services) across classes; among other things, MECo ignores the effects of shared equipment service drops.

### *A. Extra Distribution Costs of Serving Large Customers*

**Q: What are the additional costs of serving large customers on the distribution system?**

A: MECo does not reflect any expenditures made to meet the higher reliability, power-quality and load-density requirements of large commercial and industrial customers. Some of these expenditures provide some additional benefit to residential customers (even though they do not necessarily value it very highly), but some of the expenditures are undoubtedly concentrated in areas that serve primarily large customers, or are provided to individual customers, such as service from multiple feeders.

**Q: Have you quantified any costs of serving the power quality needs of MECo's large customers?**

A: I did not make any concerted effort to quantify these costs, which would probably require a detailed review of MECo distribution-project justification documents. Since many of the expenditures discussed above may be covered by "blanket" authorizations, the detail required for this review may be very fine.

However, I did find one example of MECo providing power-quality services primarily to serve large customers, and charging the costs primarily to small customers. IR DPU 2-17 describes a program for helping customers identify and deal with power quality problems. MECO explains that

> In the late 1980s, MECo, as did most utilities in the nation, began to experience a growing number of customer complaints related to power disturbances. Customers were becoming upset over "glitches" in their power, resulting in business disruption, lost production and often costly downtime. It soon became apparent that the quality of the utility service hadn't deteriorated. What was changing was the level of complexity and the inherent intolerance to minor power disturbances associated with the new generation of electrical equipment. This change was a direct result of solid state electronics...(IR DPU 2-17)

The problems that prompted customers to participate included "flickering lights, computer system 'crashes,' malfunctioning kidney dialysis units, and in one case, adjustable speed drive presses at a regional sewage treatment facility tripping off line, resulting in unprocessed solid waste overflowing onto the facility floors." (Id.)

The program includes

- Meeting with customers to learn about specific power problems

- Conducting visual inspections of customer processes and equipment
- Installing sophisticated diagnostic equipment
- Analyzing the diagnostic data...
- Outlining alternative solutions...
- Providing a list of qualified vendors...
- Helping review vendor proposals if requested
- Retesting customer facilities to verify that the problem was resolved (Id.)

While MECo claims that the 1994 participants ranged "in size from the individual homeowner to one of MECo's largest industrial customers," of the 178 MECo customers to have participated in this program, only three (or 1.7%) have residential rate codes, while 93 (or more than half) are G-3/4 customers.[31] Given the description of the program, the small participants in the program probably did not require a proportional share of the costs, since the walk-through will be quicker, fewer points in the electrical system need be monitored, interactions between pieces of equipment will be simpler, and so on.[32] Yet MECo allocates this expense on customer number, allocating 89% of the costs to residential class (which received no more than 1.7% of the services) and only 0.23% to G-3/4 (which received over half the services).

**Q: How should this cost be allocated?**

[31] The response to IR AG 14-6b shows that the distribution of the 35 test-year participants was even more skewed, with no residential participants, one G-1 participant, and the remaining 97% of participants from G-3/4.

[32] I find it hard to believe that the one apparently single-family house served by the program (an R-4 customer in N. Egremont) required or received the same level of services as the several hospitals, hotels, or the Worcester Centrum.

A: The costs of the power quality assessment program incurred for each class should be assigned to that class. If those costs cannot be determined, MECo should allocate the program costs on the number of participants, weighted by the participants maximum demand (as a proxy for complexity of treatment). Even an unweighted participant allocator would reallocate about 88% of the program costs from the residential class to the general service classes.

**Q: What is the relevance of the power quality assessment program to the allocation of distribution investments to improve power quality?**

A: It is clear that power quality is overwhelmingly a concern of large customers. Using the participation in the power quality assessment program as a proxy for the pressure from customers for improvements in the distribution system, the costs of those improvements should be allocated as follows:

| Class | R-1/2 | R-4 | G-1 | G-2 | G-3/4 |
|---|---|---|---|---|---|
| Cum. Participants | 2 | 1 | 41 | 38 | 94 |
| Cum. Allocation | 1.12% | 0.56% | 23.03% | 21.35% | 52.81% |
| Test Yr Allocation | 0.00% | 0.00% | 2.94% | 0.00% | 97.06% |

MECo should be ordered to identify projects and expenditures intended to improve power quality, and allocate those costs on the test-year allocator above, or the cumulative allocator weighted by the average maximum demand of the participants.

*B. Energy-related Distribution Investment*

**Q: Does MECo properly classify costs to demand?**

A: No. MECo allocates all distribution costs on demand or customer number. In reality, a significant portion of the distribution investment, particularly in underground lines and transformers is required for total daily or weekly energy usage, not for peak load.

**Q: How does energy use in hours other than the peak hour affect the installed cost of transformers?**

A: There are at least three ways in which energy use determines the sizing, and hence the cost, of transformers. The first two factors—the length of the peak period and the load factor on the transformer—affect the maximum load the transformer can tolerate without catastrophic overheating. The third factor is the effect of periodic overloads on useful transformer life.

Short peaks and low off-peak currents allow the transformer to cool between peaks, so that it can tolerate a higher peak current. The limit for very short-duration loads (e.g., 30 minutes) is generally stated as 200% of rated capacity, while utility practice for high load factors (e.g., 80%) and long peak periods (e.g., 8 hours) often limits loadings to 100%–120% of rated capacity, especially for underground service.

Thus, only about half the installed transformer capacity would be necessary to meet the brief peak loads represented in MECo's demand allocators, were it not for the neighboring hours of high utilization and the relatively high off-peak loads on peak days. Even considering only system reliability considerations, only 50%–60% of transformer capacity can be attributed to the single-hour peak load.

Energy usage also affects the useful life service life of transformers, due to overheating of the insulation. For example, a transformer that is overloaded by 20% for eight hours (due to high load, or failure of another transformer in a network), will lose about 0.25% of its useful life. With 10 overloads annually at this level, the transformer would last 40 years, by which time accidents, corrosion, and other problems are likely to lead to its retirement. Long overloads and higher load levels increase the rate of aging per overload, and frequent overloads lead to rapid failure of the transformer.

In a low-load factor system, these high loads will occur less frequently, and the heavy loading will not last as long. If the only high-demand hours were the ones on which the peak loads are based, the chances of a first contingency coinciding with the peak would be small, and most transformers would be retired for other reasons before they experienced many overloads. In this situation, larger losses of service life per overload would be acceptable, and the short peak would allow greater overloads for the same loss of service life.

With high load factors, there are many hours of the year when the transformers are at or near full loads.[33] Thus, the size of the transformer must be increased to limit overloads to the small amount that is compatible with acceptable loss of service life per overload for this frequency of overloads, or the transformer will burn out far too rapidly.

Exhibit AG-PLC-19 contains excerpts from various references, demonstrating the dependence of transformer capacity on energy loading.

**Q: What portion of distribution transformer capacity might be classified as energy-serving?**

A: For other utilities, I have estimated this percentage at about 40%. The classification of distribution transformer costs on energy, rather than customer peaks, would significantly reduce the allocation to the residential, small commercial, and streetlighting classes.

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[33]In networks, failure of other transformers or lines will frequently cause overloading at such times.

**Q: Do the same energy-related considerations apply to substation transformers?**

A: Yes. The sizing and aging of substations is also driven in part by energy effects.

**Q: What effect does energy use have on the sizing and aging of lines?**

A: As I mentioned previously, MECo's classification methodology ignores the effect of load factor on the sizing of underground transmission, primary and secondary lines. Since heat builds up around the lines, the length of peak loads and the amount of load relief in the off-peak period affects the sizing of underground lines. An underground line may be able to carry twice as much load for a needle peak as for an eight-hour peak with a high daily load factor. To reduce losses and the build-up of heat, utilities must install larger cables, or more cables, than they would to meet shorter loads.[34] Since the number and sizing of underground lines is a function of load factor, a portion of the cost of the lines should be classified as energy-related.

Exhibit AG-PLC-20 contains excerpts from various references, demonstrating the dependence of power-line sizing on energy loading.

### *C. Allocation of Distribution System on Customer Maximum Demand*

**Q: How does MECo allocate demand-related distribution plant?**

A: According to IR 2-3 (revised), MECo has allocated primary, step-down transformer and secondary distribution plant according to the average over 12

[34]Both lines and transformers are sized, in part, to reduce the costs of energy losses. This consideration also argue for classifying a portion of transmission and distribution costs as energy-related.

months of the monthly sum of individual customers' maximum demands.[35] This demand measure totals 6,324 MW at primary, compared to MECo's July 1994 coincident peak of 2,799 MW (WP PTZ-2, p. 4). MECo's cost allocations effectively assume that its engineers ignore customer load diversity in designing the distribution system.[36]

**Q: How does load diversity influence the sizing of demand-related distribution plant?**

A: The diversity of demand among a group of customers results in a group peak demand that is lower than the sum of customers' individual maximum demands. In general, utilities size plant to meet the group peak, not the sum of customers' individual maximum demands.

The load diversity on a given piece of distribution equipment, a transformer or a length of line, depends upon the number and type of customers served on that plant. The farther downstream the distribution equipment, the fewer the customers served, and the lower the load diversity.

NEES's Distribution System Planning Guidelines show that NEES designs its underground distribution system to reflect the significant diversity

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[35] The Company appears to have been confused by its own terminology, as evidenced by its need to correct IR AG 2-3. Zschokke (p. 15) defines the "Non-Coincident Peak" allocator as "rate class' individual customer 12 monthly class peaks." This is a non-standard use of the term "Non-Coincident Peak." The *NARUC Electric Utility Cost Allocation Manual*, which clearly uses class NCP as the sum of the diversified peaks of each class, and contrasts NCP with "the summation of individual customer maximum demands" (page 97, January 1992 edition). To avoid confusion, I refer to the normal meaning of NCP as *Class Peak* and to MECo's use of the terms as *Sum of Maximum Customer Demands*.

[36] If MECo argues in this case that it actually ignores diversity in planning, the Department should initiate an investigation to determine the cost of the excess distribution capacity that was imprudently installed.

in groups of residential customers, as shown in Exhibit AG-PLC-21. Other examples of utilities designing distribution systems to reflect the diversity of customer loads (especially for small customers) are provided in Exhibit AG-PLC-22.

**Q: What evidence suggests that the loads on the various portions of distribution plant are diversified, and hence lower than the sum of customer maximum demands?**

A: MECo's 1994 FERC Form 1, p. 427.3 reports a total distribution substation capacity of 2,711 MVA. The total substation capacity serving MECo customers may be somewhat larger than 2,711 MW, since the FERC Form data do not include substations serving individual industrial customers, or NEPCo substations directly serving a few large MECo customers; or somewhat smaller, since each MVA is equivalent to less than one MW.[37] In any case, it is clear that the substations would not carry 6,324 MW of primary load.

**Q: What is the effect of using the sum of customer peaks, rather than the loads of a group of customers sharing a piece of equipment?**

A: MECO allocates too much of the costs to small customers. Small customers loads are highly diverse; in a given year, various customers will peak at different times, on different days, and in different seasons. The diversity of load that occurs between groups of small customers occurs to some extent within each large customer, as different pieces of equipment, functions, and parts of the facility peak at different times. Under MECo's methodology,

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[37] The ratio between MW of useful power and MVA of apparent power is the power factor, which typically ranges from 80-90%.

residential class is assigned 66% of non-customer-related distribution plant, as follows:

| | |
|---|---|
| Primary lines and Substations | 61% |
| Step-down Transformers | 67% |
| Secondary Lines | 77% |

**Q: What would be a more appropriate allocator for distribution plant and associated expenses?**

A: If MECo were to use a single type of load to allocate all distribution equipment, that allocator should be the class non-coincident peaks (NCPs), which reflect both the sharing of equipment between customers and the tendency of various classes to have different load shapes, and often (although not always) to use different distribution equipment.[38] In DPU 92-78, the Commission ordered MECo to use class NCPs, averaged over the twelve months of the year to reflect the diversity of maximum loads on distribution equipment.[39] Instead of using class NCPs, MECo applied the sum of customer maximum demands; MECo used the name required by the Department, but not the data.

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[38]Even using a single measure of load, the allocators will vary with the voltage level of the equipment, since the mix of class loads will vary with voltage.

[39] To clarify the terminology, the Commission cited the *NARUC Electric Utility Cost Allocation Manual*, distinguishing "customer class non-coincident demand" from "individual maximum demands." (DPU 92-78 at 150). As noted above, the *Cost Allocation Manual* clearly uses "class NCP" as the sum of the diversified peaks for the classes. The Commission also noted that MECo argued for reflecting customer diversity in allocating distribution costs (Id. at 153), stated that the load measure the Commission called "NCP" is one that does "reflect the diversity of individual customers within a class" (Id. at 154), and found reasonable the 12-month average of that form of NCP (Id. at 155).

**Q: How would the use of class peaks, rather than the sum of customer peaks, affect MECo's allocation of distribution plant?**

A: The effect would be substantial. The following table shows the residential portion of class and customer loads at each level of the distribution system.

| | DPU-Ordered Class Diversified Peak | MECo-Utilized Customer Undiversified Peak |
|---|---|---|
| primary lines and substations | 41% | 61% |
| step-down transformers | 52% | 67% |
| secondary lines | 63% | 77% |

Source: WP PTZ-3, p. 4

**Q: Is class peak the best estimate of class contribution to load at each voltage level?**

A: No. While class peak is the best single measure, the diversity of loads varies with the type of equipment. At the highest distribution voltage level, the costs of substations and primary lines are determined by area-specific loads that tend to be dominated by particular classes. However, a single primary feeder is likely to serve some mix of residential, commercial, industrial, and/or street lighting customers, and not just one type of customer. Substations are even more likely to serve mixes of customers, since they serve several feeders.

Generally, the load diversity of a group of customers from different rate classes will be greater than that for a group of customers from the same class, but lower than the load diversity for the system as a whole. Therefore, the allocator for primary lines should be somewhere between the system coincident peak and class non-coincident peak. One reasonable allocator for primary lines and substations would be a simple average of (1) class contribution to MECo coincident peak with (2) class peak (the normal definition of non-coincident peak), with a seasonal weighting to reflect the timing of feeder and substation peaks. MECo does not seems to have provided either of these peak measures, or any information on the timing of primary equipment peaks.[40]

**Q: What effect does diversity have on the appropriate demand allocators for step-down transformers?**

A: The demand allocator for transformers should reflect the effects of customer load diversity on the number and size of line transformers. On average over all customer classes (excluding street lighting), MECo has over 931,000 customers (Exhibit PTZ-1, p. 17),[41] but less than 134,000 step-down transformers in use to serve customers (1994 FERC Form, p. 429), or an average of 7 customers per transformer. Since each large customer may have one transformer, or even several transformers, dedicated to serving its load, the ratio of small customers per transformer is even larger. MECo prefers to serve 9–12 customers per transformer for medium-use residential customers (NEES Distribution Standard 2521, reproduced in Exhibit AG-PLC-21).

MECo assumes the following coincidence factors for groups of residential customers, even when only diversity among customers with the same type of air conditioning and heating equipment is considered:

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[40] Interestingly, when MECo does provide monthly class peaks (in Workpaper PTZ-2, p. 3), the data for Rates G-2 to G-4 are inconsistent with the annual averages in WP PTZ-3, p. 4, and also with the sum of maximum customer demands in Exhibit PTZ-1, p. 17. The sum of maximum customer demands must exceed the class peak, but the monthly class peaks in WP PTZ-2 are higher than the monthly sum of maximum customer demands in IR AG 2-3.

[41] This total is from the allocator for "number of customers excluding street lights," divided by 12.

| Number of Customers | Coincidence Factor |
|---|---|
| 8 | 0.55 |
| 9 | 0.53 |
| 12 | 0.50 |
| 13 | 0.49 |
| 20 | 0.46 |

In other words, the maximum load on the transformer is typically about half the sum of the maximum loads of the customers served by the transformer. Hence, while MECo allocates step-down transformers to the residential class based on a 3,544 MW sum of customer peak demands, the class's load at the transformer is more like $0.55 \times 3{,}544 = 1{,}630$ MW.

Exhibit AG-PLC-23 shows the effect of applying this adjustment to all classes, assuming eight customers per transformer for Rate R1/R2, and smaller numbers for classes with larger customers. The residential share of transformer costs falls from 67% to 56%, while the share allocated to Rate G-3/4 rises from 12% to 19%.

**Q: How does diversity affect the sizing of secondary lines?**

A: The effect is similar to that for transformers, but the effect is reduced, since fewer customers are served on each piece of primary. For the sample layout given in NEES Distribution Standard 5002 (in Exhibit AG-PLC-21), about half the secondary line length (sections AB and AE) serves 4 customers and the other half (BC, AD, and EF) serves two customers, for an average of three customers.

Fewer of the larger G-1 and G-2 customers served from the secondary system would tend to share secondary lines, and their coincidence factors are higher, so the residential share of the secondary demand allocation would decrease, as shown in Exhibit AG-PLC-24.[42]

Any G-3 or G-4 customers served off the secondary lines would be added to this computation, and would have fairly low diversity.

**Q: Do you have any other comments on MECo's allocation of secondary lines?**

A: Yes. MECo allocates no secondary lines to any G-3 or G-4 customers, even though Exhibit PTZ-7, p. 25, 37% of G-3 sales and 91% of G-4 sales are to customers who receive neither the credit for metering at primary nor the credit for delivery at primary. This allocation would be correct only if all G-3 and G-4 customers take service directly from the transformer, without any intervening secondary lines. In particular, any G-3 or G-4 load on secondary networks would utilize secondary lines.

### *D. The Weighting of Customer Allocators*

**Q: Where does MECo use customer allocators inappropriately?**

A: MECo ignores differences in sizes and costs of services; and in differential requirements for meter reading and customer service.

**Q: How does MECo allocate service drops?**

A: The Company claims to have developed a weighted customer allocator based on an engineering study of the unit cost of services. The results are presented in Exhibit PTZ-3, p. 15. The source cited for the estimates is WP PTZ-2, pages 4-5; those pages have nothing to do with services. Nor does the

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[42] I assume that the number of G-1 and G-2 customers sharing the average secondary line is (1 + customers/transformer) ÷ 2, from in Exhibit AG-PLC-23.

service-drop analysis appear anywhere else in MECo's workpapers. Whatever this analysis does, it has hardly made a difference from the residentials point of view:

| | Residential Allocation |
|---|---|
| Number of Customers | 89% |
| Service Drop Allocator | 88% |

It is not surprising that the allocation is not very different from a pure customer allocator, since the computation in Exhibit PTZ-3 simply multiplies the number of customers by an asserted marginal cost per service, and the range in service costs is only about 2.5:1. Not only is this small variation in service costs for a wide variety of services (single-phase and three-phase, primary and secondary, from 60 amps to many hundreds of amps) surprising, but the pattern is even more surprising. The small commercial customers, with loads twice as great as the residential customers, are asserted to have lower service costs than the residentials, while the G-2 services are reported to be more expensive than those for the much larger G-3/4 customers.

**Q: Has MECo assigned the proper number of service drops to each class?**

A: No. The Company did not take into account the sharing of services by smaller customers in the development of the relative unit costs. The calculation in Exhibit PTZ-3, p. 15 assumes each customer has a service. But several customers in a multi-family dwelling, a shopping center, or an office building, may share a single service.

I estimated the number of shared services as the difference between the number of customers and the number of services. From page S-14 of MECo's 1994 return to the DPU, I found that as of year-end 1994, MECo had 587,124 services in place, to serve about 929,000 non-streetlighting customers.[43] Customers exceeded services by 58%. Thus, there are about 342,000 more customers than services.

**Q: What other problems have you identified with this allocator?**

A: The allocation appears to have the following problems:

- According to Zschokke (p. 14), MECo calculated the unit cost by meter type. But a small residential customer served by a 60 amp service and a G-1 customer served by a 200 or 300 amp service may use the same meter type.
- Service costs vary with voltage level, length, ampacity, number of phases, voltage stability requirements, and overhead versus underground. There is no indication that the engineering study considered differences in these characteristics between classes.
- The study is represented as estimating marginal costs, not embedded costs. It may therefore be allocating costs as if all residential customers were new "marginal" customers with 200 amp underground services (which may be typical today), even though many customers have 60 amp or 100 amp services, and many of those are overhead in older areas. Marginal and embedded costs may be much closer for the large customers than for the small customers.

**Q: How should MECo modify its service allocator?**

A: The customer allocator should be modified to take into account the sharing of services by some small customers. In addition, MECo should be ordered to reanalyze the costs, demonstrating that it has properly reflected the size, length, number of phases, and construction (overhead versus underground) of

[43] Some of these services may be inactive.

the embedded services, through a survey or representative sample of services associated with each type of customer.

**Q: Where does MECo improperly use unweighted customer allocators?**

A: MECo uses the unweighted customer allocator (or the very similar bill allocator) for

- customer account supervision expense;
- customer records and collections;
- miscellaneous customer account expense;
- customer service and information expenses;
- a "customer-related" portion (16.55%) of distribution O&M accounts covering what MECo calls "overhead": supervision, engineering, miscellaneous expenses, and rents; and
- installation expense on customer property (Account 587).

None of these expenses appears to be directly proportional to customer number.

**Q: Please explain why.**

A: In general, larger customers would be expected to have more complicated installations, metering, and billing, and to warrant more time and attention from MECo. It is difficult to believe that MECo spends as much time and attention on each residential customer as on each G-3 customer, considering that the average G-3 customer's bill is about 700 times as large as the average residential bill.[44] More specifically:

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[44]For example, in explaining how the SED contract would be marketed, MECo witness Reilly testified that "We intend to speak personally with each of the G-3 customers, one-on-one, individual contacts with each of our G-3 customers." DPU 93-194 (November 22, 1993) Tr. at 35. Understandably, MECo does not provide comparable levels of customer service or

- *Customer account supervision* includes supervision of meter reading and uncollectibles, both of which MECo acknowledges are more heavily weighted towards larger customers.
- The records portion of *customer records and collections expense* should vary with the complexity of the billing, and collections expense should vary with uncollectibles, both of which are greater per customer for large customers.
- *Miscellaneous customer account expense* is a very small category, but is likely to be greater for large customers with complicated bills, including many billing determinants and credits.
- Nearly 10% of the *Customer service and information expenses* are comprised of the power quality assessment program, which serves almost entirely commercial customers. Once again, it is difficult to believe that MECo spends as much time providing assistance and information on billing, energy usage, and other matters for the average residential customer as for the average hospital or manufacturer.
- The *"customer-related" portion of distribution O&M* is determined in MECo's classification process (Exhibit. PTZ-2, p. 7) by the fraction of total distribution plant that is comprised of services, meters, and streetlights, in about equal parts.[45] Roughly one third of this amount is

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information to residential customers to assist them in utilizing new rate designs. While this difference in treatment may be justified by the lower cost-effectiveness of additional service to small customers, residential customers are already burdened by the lack of better information and service, and should not be paying for services for which they are not eligible.

[45] MECo's decision to allocate a portion of rents to meters, services, and streetlights appears to be improper, since MECo is unlikely to be renting this equipment or land for it.

driven by streetlighting (for which residential should have no responsibility), one third by meters (51% of which MECo allocates to residentials) and one third by services (88% of which MECo allocates to residentials).[46] A simple average of these three allocators would allocate about 45% of the accounts; yet MECo allocates 89% of this "customer-related" overhead to the residential class, more than any of the costs that drive it. "Customer-related" distribution overheads should be allocated in proportion to the underlying costs, as derived in Exhibit AG-PLC-26.

- Installation expense on customer property (Account 587) includes installing such items as cable vaults, motor generator sets, motors, and switchboard panels, all of which would be primarily provided for large customers with complicated service requirements; and investigating service complaints (which are primarily associated with large customers, as shown by the power quality assessment program). The frequency and magnitude of these costs would tend to vary with the size of the customer, and are unusual for small customers. Unless MECo has a breakdown of these costs by customer class or other characteristics, they should be allocated on the basis of customer demands at primary.[47]

**Q: How would you recommend allocating the customer account and customer service expenses?**

A: As noted above, I recommend allocating

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[46] As discussed in §IV.C, I believe this allocation is overstated.

[47] A further weighting towards large customers would be warranted, but is difficult to estimate.

- the $567,729 portion of Account 908 that is due to the power quality assessment program on the basis of participation;
- "customer-related" distribution overheads in proportion to the underlying costs, as derived in Exhibit AG-PLC-26; and
- installation expense on customer property on the basis of customer demands at primary.

Further, I recommend that customer records and collections expense be allocated in a manner that reflects the greater complexity of billing for the customers with more complex rates, and the greater effort undertaken to collect overdue bills from the larger customers. In the absence of any special study, I recommend using the average of the meter reading and uncollectibles allocators.

I would allocate customer account supervision and miscellaneous customer account expense in proportion to the total of other customer account expenses.

I would allocate the remainder of the customer service expenditures on an average of customer number and energy, to reflect the greater effort MECo takes to serve large customers.

These allocators are summarized in Exhibit AG-PLC-25.

## V. Allocation of Discounts and Credits

**Q: What discounts and credits will you be discussing?**

A: I discuss the service extension discounts (SED) and economic development discounts.

### *A. Service Extension Discounts*

**Q: You have previously described the Service Extension Discount. How should the payments from NEPCo to MECo to subsidize the SED be allocated to classes?**

A: If rates are otherwise set right, SED payments from NEPCo should be allocated in the same manner as the costs. If costs are allocated to G-3, without discounts, then the SED credit from NEPCo should similarly be allocated to Rate G-3. If costs are reallocated to other classes, so should be the SED credit. From IR AG 2-12, I understand that MECo is using the first approach, but the discussion is not totally clear.

If rates continue to be set as they are today, the G-3 customers not on the SED contract are imposing costs on the system for which they are not paying, as I discussed in §III.F above, and are being subsidized by ratepayers in other classes. In that case, the NEPCo credit should be allocated to all customer classes, using WHAM-D (through which most of these costs are collected) to compensate them for the costs they are bearing.

### *B. Economic Development Discounts*

**Q: How does MECo propose to allocate economic development discounts?**

A: MECo proposes to allocate economic development discounts, ~~under the Flex Rate G-5~~, on rate base.

**Q: How has the Department allocated comparable discounts?**

A: In DPU 93-42, the Department found that the costs of revenue reductions under experimental rates ~~(a description that seems to fit Rate G-5)~~ should be allocated to the shareholders. The Department similarly found that the discounts in Boston Edison's Manufacturing Retention Rate should be paid by the shareholders. Thus, it is not clear that these discounts belong anywhere in MECo's cost of service.

**Q: Is rate base an appropriate allocator for any portion of the economic development discounts that might be recovered from ratepayers?**

A: No. The rate-base allocator is consistent with allocation of residential low-income rate discount, but does not well match the causation of the economic development discounts.

The economic development discounts would attract additional general service load, which would spread some fixed MECo and NEPCo costs over larger sales. However, the additional load would presumably increase costs, even in the short term, for fuel, metering, services, and other customer-related costs. Therefore, the discounts should be allocated to rate classes in proportion to the benefits they receive from the increased sales, which would be the costs that will be spread over a larger base. Those benefits would be roughly proportional to each class's allocation of MECo costs, excluding meters, services, and customer-related costs, plus MECo's share of NEPCo's non-fuel costs. MECo should be instructed to develop an appropriate allocator. In the meantime, the discounts should be allocated on the basis of revenues, rather than rate base.

## VI. Summary of Recommendations

**Q: Please summarize your recommended changes in cost allocation.**

A: First, as I explain in §III, the costs of the excess capacity and excess baseload generation in NEPCo's resource mix charged to MECo should be allocated to rate classes in proportion to their contribution to the errors the forecasts that contributed to the excess. This change would shift large portions of production costs from the residential and streetlighting customers to the large general-service class.

Second, as discussed in §IV.C., the costs of the distribution system, at the primary, transformer, and secondary levels, should be allocated to rate classes on the basis of diversified class peaks, or of diversified group loads by voltage level, rather on undiversified customer peaks.

Third, several expense items that MECo allocates in proportion to number of customers or bills should be allocated in ways that better reflect their causation, as discussed in detail in §IV.D. These costs include customer accounts, customer service, distribution overheads, and the power quality program.

Fourth, the costs of the economic development discounts should be allocated to rate classes in proportion to revenues, not rate base.

Fifth, excess generation costs are not re-allocated as recommended above, the subsidy from NEPCo for reducing forecasting risk with Service Extension Discounts should be allocated on basis of the production demand allocator (WHAM-D).

The reallocation of generation costs alone results in a reduction in the residential revenue requirement of $69 million, more than MECo's proposed rate increase for residential customers, as well as a similar shifts for streetlighting customers. The other corrections in cost allocations on the distribution system would further reduce the costs allocable to the small classes. Therefore, based an equitable sharing of costs would result in no rate increase for the residential class, and smaller increases for small commercial and streetlighting than recommended by MECo. If the Commission explicitly finds that specific non-equity considerations or policy objectives require that the residential class receive some rate increase, that increase should be the minimum required for consistency with the other objectives.

**Q: Please summarize your recommendations regarding additional analyses MECo should perform to support more equitable cost allocations.**

A: Commission should order MECo to undertake the following additional analyses to support improvements in future cost-of-service studies:

- Determination of the relative costs of serving various classes' loads, given historical and expected risks of variation in sales from forecast.
- Determination of the relative costs by class of service drops, considering the length of services, the average installed amperage, the mix of single-phase and three-phase services, and the mix of underground and overhead services.
- Identification of any secondary lines serving customers in Rate G-3/4.
- Differentiation of target generation reserve margins by rate class.
- Identification of transmission and distribution investments made to support the higher requirements for reliability and power quality of large customers.
- Classification as energy-related the portion of transformer and underground line costs resulting from energy loadings, including the effects of thermal limits imposed by long peaks and high load factors, and the effects of multiple overloads on equipment life.
- Development of an economic-development allocator, reflecting MECo costs, excluding meters, services, and customer-related costs, plus MECo's share of NEPCo's non-fuel costs.

**Q: Does this conclude your testimony?**

A: Yes.

**Exhibit ____ (AG-PLC-2)**
**NEES's Position on Raising Residential Rates,**
**From 1995 Presentation to Investment Analysts**

**(4 pages, including this cover page)**

# New England Electric

Massachusetts Electric Company
The Narragansett Electric Company
New England Power Company

# Rating Agency Presentation March 1995

AG-1-10
Att. 2

# NARRAGANSETT RATE FILING DESIGNED TO MEET INVESTORS' AND CUSTOMERS ' NEEDS

- Filed 3/1/95
- Full Case Proposal
  - $30 M (6.4%); effective 12/95
  - Includes $7M for increased funding of storm fund and higher depreciation rates
  - Requested 12% ROE
  - Over 80% of increase to residential and small C&I
  - Large C&I only 1.8% increase
  - Manufacturer's discount of 8% off base rates ($3 M)
    - must sign SED
- Rate Moderation Proposal
  - $10 M net including manufacturers discount (2%) effective 6/1/95
  - $20 M (4.2%); effective 6/1/96

# MASS ELECTRIC FILING DESIGNED TO MEET INVESTORS' AND CUSTOMERS' NEEDS

- File for Approximately $60 MM Increase on March 15 (4%)
  - October 1 effective date
- Majority of Increase Allocated to Residential
- Discounts for Large C&I Customers Who Agree to 5 Year Minimum Take Provisions
- Incentive Rate Proposal

**Exhibit ____ (AG-PLC-3)**
**Summary of NEPCO Purchases and Sales**

**(9 pages, including this cover page)**

NEW ENGLAND ELECTRIC SYSTEM

# EEI FINANCIAL CONFERENCE

## SAN DIEGO, CA

October 30 - November 2, 1994

PRESENTATION TO UTILITY ANALYSTS

| | MW (Winter) | Fuel | Status | Expected Start Date | Contract End Date | Type Plant | NEES % Owner | Dispatch? | Capacity In Fuel Clause? | NPV of Fixed Charges (If split) | NPV of Total Charges (If not split) | Debt Equivalent Factor | Debt Equivalent |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Take & Pay Contracts:** | | | | | | | | | | | | | |
| Hydro-Quebec Energy Contract | 222.43 | Hydro | On-line | --- | Dec-2000 | U | | Limited | NA | 0 | 0 | 0% | 0 |
| Lawrence Hydroelectric Associates | 14.10 | Hydro | On-line | --- | Dec-2011 | QF | | N | Y | | 35,771 | 5% | 1,789 |
| Mascoma Hydro Corp. | 1.50 | Hydro | On-line | --- | Jan-2029 | QF | | N | Y | | 2,942 | 5% | 147 |
| Pontook Operating Limited Partnership | 10.70 | Hydro | On-line | --- | Jan-2012 | QF | | N | Y | | 33,053 | 5% | 1,653 |
| Northeast Landfill Power - Johnston, RI | 12.00 | Methane | On-line | --- | Jan-2010 | QF | | N | Y | | 35,477 | 5% | 1,774 |
| Turnkey, Rochester NH | 3.00 | Methane | On-line | --- | Feb-2009 | QF | | N | Y | | 10,829 | 5% | 541 |
| Ogden Martin Systems of Haverhill | 42.87 | Waste | On-line | --- | May-2019 | QF | | N | Y | | 290,754 | 5% | 14,538 |
| Refuse Energy Systems Co - Saugus | 32.28 | Waste | On-line | --- | Dec-2015 | QF | | N | Y | | 185,997 | 5% | 9,300 |
| Refuse Energy Systems Co - N. Andover | 31.98 | Waste | On-line | --- | Jun-2005 | QF | | N | Y | | 45,691 | 5% | 2,285 |
| Wheelabrator Millbury | 40.73 | Waste | On-line | --- | Sep-2017 | QF | | N | Y | | 285,743 | 5% | 14,287 |
| Barre Landfill (1) | 1.00 | Methane | Licensing | Jul-95 | Jun-2010 | QF | | N | Y | | 2,229 | 5% | 111 |
| Genesis Landfill - Johnston (1) | 1.95 | Waste Heat | Licensing | Jan-96 | Dec-2010 | QF | | N | Y | | 3,483 | 5% | 174 |
| Nashua Landfill (1) | 1.50 | Methane | Licensing | Jan-96 | Dec-2006 | QF | | N | Y | | 1,774 | 5% | 89 |
| Plainville Landfill (1) | 3.00 | Methane | Licensing | Jan-96 | Dec-2010 | QF | | N | Y | | 4,196 | 5% | 210 |
| Randolph Landfill (1) | 2.64 | Methane | Licensing | Jan-96 | Dec-2015 | QF | | N | Y | | 4,961 | 5% | 248 |
| TIRU - Shirley | 5.88 | Waste | Licensing | Jan-97 | Dec-2016 | QF | | N | Y | | 8,899 | 5% | 445 |
| NEP Windplant 1 phase I | 10.00 | Wind | Licensing | Jan-97 | Dec-2021 | QF | | N | Y | | 9,425 | 5% | 471 |
| NEP Windplant 1 phase II | 2.50 | Wind | Licensing | Jan-98 | Dec-2022 | QF | | N | Y | | 2,292 | 5% | 115 |
| NEP Windplant 1 phase III | 7.50 | Wind | Licensing | Jan-99 | Dec-2023 | QF | | N | Y | | 6,723 | 5% | 336 |
| Altresco of Pittsfield | 112.27 | Gas | On-line | --- | Aug-2010 | QF | | Y | Y | 303,966 | | 5% | 15,198 |
| Clark University | 0.03 | Gas | On-line | --- | Jun-2002 | QF | | Y | Y | | 20 | 5% | 1 |
| Enron Power Enterprise Corp (2) | 83.44 | Gas | On-line | --- | Jan-2009 | IPP | | Y | N | 178,553 | | 5% | 8,928 |
| Pawtucket Power Associates | 64.28 | Gas | On-line | --- | Jan-2011 | QF | | Y | Y | 185,305 | | 5% | 9,265 |
| Total Take & Pay | | | | | | | | | | 667,824 | | | 81,904 |
| **Take or Pay Contracts:** | | | | | | | | | | | | | |
| Ocean State Power | 272.58 | Gas | On-line | --- | Oct-2011 | IPP | 20.0% | Y | Partly | 608,920 | | 25% | 152,230 |
| Connecticut Yankee Atomic Power Corp | 87.50 | Nuclear | On-line | --- | Jun-2007 | U | 15.0% | Limited | N | 247,188 | | 25% | 61,797 |
| Maine Yankee Atomic Power Corp | 158.05 | Nuclear | On-line | --- | Oct-2008 | U | 20.0% | Limited | N | 290,819 | | 25% | 72,705 |
| Vermont Yankee Nuclear Power Corp. | 93.90 | Nuclear | On-line | --- | Mar-2012 | U | 20.0% | Limited | N | 297,683 | | 25% | 74,421 |
| Canal 1, Canal Electric - Comm Energy (3) | 143.00 | Oil | On-line | --- | Jul-2002 | U | | Y | N | 65,998 | | 40% | 26,399 |
| Middletown 4, NU | 55.60 | Oil | On-line | --- | Oct-95 | U | | Y | N | 1,970 | | 40% | 788 |
| Oswego 4, Niagara-Mohawk | 40.00 | Oil | On-line | --- | Dec-95 | U | | Y | N | 2,126 | | 40% | 851 |
| NU Slice Purchase (4) | Variable | Mixed | On-line | --- | Oct-98 | U | | Y | N | 47,714 | | 40% | 19,085 |
| Total Take or Pay | | | | | | | | | | 1,562,417 | | | 408,276 |
| **Firm Power Sales Contracts:** | | | | | | | | | | | | | |
| Salem Harbor 4 to Newport (EUA) | 5.00 | Oil | On-line | --- | Oct-95 | U | | | | (474 | | 40% | (189) |
| Brayton Point 4 to Newport (EUA) | 5.00 | Oil/Gas | On-line | --- | Oct-95 | U | | | | (467 | | 40% | (187) |
| Wyman 4 to Newport (EUA) | 5.00 | Oil | On-line | --- | Oct-95 | U | | | | (208 | | 40% | (83) |
| Salem Harbor 3 to Unitil | Variable | Coal | On-line | --- | Oct-2005 | U | | | | (10,551 | | 40% | (4,220) |
| Millstone 3 to Unitil | Variable | Nuclear | On-line | --- | Oct-2005 | U | | | | (7,068 | | 40% | (2,827) |
| System Slice to Reading Mun. Light Dept. | Variable | Mixed | On-line | --- | Oct-99 | U | | | | (10,005 | | 40% | (4,002) |
| System Slice to Shrewsbury | Variable | Mixed | On-line | --- | Oct-2004 | U | | | | (15,527 | | 40% | (6,211) |
| System Slice to Nantucket | Variable | Mixed | Licensing | Jan-97 | Dec-2016 | U | | | | (27,070 | | 40% | (10,828) |
| Millstone 3 /Seabrook 1 to Bangor | 25.00 | Nuclear | On-line | --- | Oct-99 | U | | | | (1,659 | | 40% | (664) |
| Bear Swamp to Central Vermont Public Svc | 8.40 | Hydro-PS | On-line | --- | Apr-98 | U | | | | (654 | | 40% | (262) |
| System Slice to Braintree | 2.00 | Mixed | On-line | --- | Oct-2004 | U | | | | (4,557 | | 40% | (1,823) |
| System Slice to Littleton | 3.00 | Mixed | On-line | --- | Oct-2004 | U | | | | (5,009 | | 40% | (2,004) |
| System Slice to Taunton | 10.00 | Mixed | On-line | Nov-95 | Oct-2005 | U | | | | (13,898 | | 40% | (5,559) |
| Manchester Street/Bear Swamp to Groton | 0.50 | Mixed | On-line | Dec-95 | Dec-2005 | U | | | | (797 | | 40% | (319) |
| Manchester Street/Bear Swamp to Hingham | 2.00 | Mixed | On-line | Dec-95 | Dec-2005 | U | | | | (3,189 | | 40% | (1,276) |
| Manchester Street/Bear Swamp to Holden | 2.00 | Mixed | On-line | Dec-95 | Dec-2005 | U | | | | (3,189 | | 40% | (1,276) |
| Manchester Street/Bear Swamp to Middleton | 0.50 | Mixed | On-line | Dec-95 | Dec-2005 | U | | | | (798 | | 40% | (319) |
| Manchester Street/Bear Swamp to North Attleboro | 4.00 | Mixed | On-line | Dec-95 | Dec-2005 | U | | | | (6,378 | | 40% | (2,551) |
| **Brokered Contracts:** | | | | | | | | | | | | | |
| Maine Yankee to Unitil | Variable | Nuclear | On-line | --- | Oct-2005 | U | | | | (2,813 | | 40% | (1,125) |
| Ocean State to Unitil | Variable | Gas | On-line | --- | Oct-2010 | IPP | | | | (43,279 | | 40% | (17,311) |
| Total Sales | | | | | | | | | | (157,592 | | | (63,037) |
| **Capacity Exchange:** | | | | | | | | | | | | | |
| Bear Swamp (NEP to Com Elec) | 50.00 | Hydro-PS | On-line | --- | Apr-97 | U | | | | (4,480 | | 40% | (1,792) |
| Canal 2 (Com Elec to NEP) | 50.00 | Oil | On-line | --- | Apr-97 | U | | | | 3,942 | | 40% | 1,577 |
| Total Exchanges | | | | | | | | | | (538 | | | (215) |
| Grand Total | | | | | | | | | | 2,072,112 | | | 426,928 |

Notes:
1. Option to terminate contracts early assumed to be exercised.
2. NEP will provide 100% of gas thereby limiting fuel cost fluctuation exposure.
3. Contract will be extended for any outage that lasts for more than 120 days. Original expiration date was October 2001.
4. Terms of NU Slice extension were renegotiated thereby fixing the capacity payments, front-end loading the capacity purchases, and reducing the total MW commitment and total cost.

| Variable Expense | 1994 Actual Estimated | Projected Variable Expense 1995 | 1996 | 1997 | 1998 | 1999 |
|---|---|---|---|---|---|---|
| **Take & Pay Contracts** | | | | | | |
| Lawrence Hydro | 4,893 | 4,977 | 4,913 | 4,847 | 4,777 | 4,698 |
| Mascoma Hydro | 346 | 349 | 349 | 349 | 349 | 247 |
| Pontook | 4,934 | 5,099 | 5,099 | 5,099 | 5,099 | 5,099 |
| Northeast Landfill | 4,102 | 4,196 | 4,284 | 4,351 | 4,431 | 4,515 |
| Turnkey, Rochester NH | 1,331 | 1,351 | 1,374 | 1,391 | 1,412 | 1,433 |
| Ogden Haverhill | 27,254 | 28,412 | 28,918 | 29,278 | 29,731 | 30,197 |
| Resco-Saugus | 18,567 | 19,257 | 19,568 | 20,014 | 20,290 | 20,574 |
| Resco-N. Andover | 4,422 | 5,501 | 5,763 | 5,918 | 6,462 | 7,152 |
| Signal-Millbury | 28,953 | 28,667 | 29,173 | 29,533 | 29,986 | 30,452 |
| Barre Landfill | | 109 | 285 | 289 | 294 | 299 |
| Genesis Landfill - Johnston | | | 289 | 500 | 506 | 512 |
| Nashua Landfill | | | 304 | 303 | 303 | 303 |
| Plainville Landfill | | | 340 | 590 | 600 | 609 |
| Randolph Landfill | | | 387 | 662 | 662 | 662 |
| TIRU - Shirley | | | | 731 | 1,254 | 1,254 |
| NEP Windplant 1 phase I | | | | 478 | 878 | 935 |
| NEP Windplant 1 phase II | | | | | 128 | 234 |
| NEP Windplant 1 phase III | | | | | | 702 |
| Altresco | 11,474 | 10,750 | 11,240 | 11,691 | 12,346 | 13,186 |
| Clark University | 11 | 3 | 3 | 3 | 4 | 4 |
| Enron | | | | | | |
| Pawtucket (Colfax) EMI | 6,376 | 7,269 | 7,578 | 8,025 | 8,666 | 8,707 |
| Total Take & Pay | 112,663 | 115,940 | 119,869 | 124,052 | 128,176 | 131,774 |
| **Take or Pay Contracts** | | | | | | |
| Ocean State | 19,335 | 21,513 | 21,401 | 22,506 | 24,361 | 26,417 |
| Connecticut Yankee | 4,327 | 3,889 | 3,005 | 2,828 | 3,123 | 3,830 |
| Maine Yankee | 4,963 | 3,902 | 3,987 | 4,092 | 4,406 | 5,456 |
| Vermont Yankee | 4,057 | 3,423 | 3,543 | 3,603 | 3,963 | 4,023 |
| Canal 1 | 14,239 | 19,858 | 22,237 | 23,294 | 24,465 | 25,618 |
| Middletown 4 (repl. Mt Tom) | 698 | 2,046 | | | | |
| NIMO-Oswego 4 | 4,466 | 1,094 | | | | |
| NU Slice Purchase | 3,729 | 2,549 | 876 | 358 | 491 | |
| Total Take or Pay | 55,814 | 58,273 | 55,048 | 56,680 | 60,810 | 65,343 |
| Total Take & Pay and Take or Pay | 168,477 | 174,213 | 174,917 | 180,732 | 188,986 | 197,117 |
| **Sales & Brokered Contracts** | | | | | | |
| Salem Harbor 4 to Newport | 314 | 89 | | | | |
| Brayton Point 4 to Newport | 273 | 338 | | | | |
| Wyman 4 to Newport | 90 | 77 | | | | |
| Salem Harbor 3 to Unitil | 338 | 459 | 686 | 1,100 | 1,071 | 1,131 |
| Millstone 3 to Unitil | 26 | 39 | 61 | 65 | 67 | 69 |
| System Slice to Reading Mun. Light Dept. | 1,073 | 2,651 | 2,771 | 2,872 | 2,958 | 2,539 |
| System Slice to Shrewsbury | 1,466 | 1,580 | 1,914 | 1,992 | 2,070 | 2,129 |
| System Slice to Nantucket | | | | 3,158 | 3,346 | 3,549 |
| Millstone 3/Seabrook 1 to Bangor | 4,457 | 5,004 | 4,772 | 4,941 | 5,487 | 5,151 |
| Bear Swamp to Central VT Public Svc | | | | | | |
| Maine Yankee to Unitil | 15 | 21 | 34 | 52 | 56 | 69 |
| Ocean State to Unitil | 1,104 | 754 | 1,154 | 1,820 | 1,970 | 2,136 |
| System Slice to Braintree | 29 | 223 | 230 | 237 | 244 | 251 |
| System Slice to Littleton | 55 | 335 | 345 | 355 | 366 | 377 |
| System Slice to Taunton | | 186 | 1,149 | 1,183 | 1,219 | 1,255 |
| Manchester Street/Bear Swamp to Groton | | 4 | 62 | 63 | 65 | 67 |
| Manchester Street/Bear Swamp to Hingham | | 18 | 247 | 254 | 261 | 270 |
| Manchester Street/Bear Swamp to Holden | | 18 | 247 | 254 | 261 | 270 |
| Manchester Street/Bear Swamp to Middleton | | 4 | 62 | 63 | 65 | 67 |
| Manchester Street/Bear Swamp to North Attleboro | | 36 | 494 | 507 | 523 | 539 |
| Total Sales & Brokered Contracts | 9,240 | 11,836 | 14,227 | 18,916 | 20,029 | 19,869 |
| **Capacity Exchange** | | | | | | |
| Bear Swamp (NEP to Com Elec) | | | | | | |
| Canal 2 (Com Elec to NEP) | 3,784 | 2,900 | 2,256 | 862 | | |
| Total Exchanges | 3,784 | 2,900 | 2,256 | 862 | 0 | 0 |
| Net Variable Charges | 163,021 | 165,277 | 162,946 | 162,678 | 168,957 | 177,248 |

| Fixed Charges | 1994 Actual Estimated | Projected Fixed Charges 1995 | 1996 | 1997 | 1998 | 1999 |
|---|---|---|---|---|---|---|
| Take & Pay Contracts | | | | | | |
| Lawrence Hydro | | | | | | |
| Mascoma Hydro | | | | | | |
| Pontook | | | | | | |
| Northeast Landfill | | | | | | |
| Turnkey, Rochester NH | | | | | | |
| Ogden Haverhill | | | | | | |
| Resco-Saugus | | | | | | |
| Resco-N. Andover | | | | | | |
| Signal-Millbury | | | | | | |
| Barre Landfill | | | | | | |
| Genesis Landfill - Johnston | | | | | | |
| Nashua Landfill | | | | | | |
| Plainville Landfill | | | | | | |
| Randolph Landfill | | | | | | |
| TIRU - Shirley | | | | | | |
| NEP Windplant 1 phase I | | | | | | |
| NEP Windplant 1 phase II | | | | | | |
| NEP Windplant 1 phase III | | | | | | |
| Altresco | 40,681 | 39,636 | 40,011 | 40,153 | 40,412 | 40,670 |
| Clark University | | | | | | |
| Enron | 17,089 | 18,626 | 19,565 | 20,530 | 21,553 | 22,627 |
| Pawtucket (Colfax) EMI | 20,192 | 23,388 | 23,400 | 23,336 | 23,336 | 23,544 |
| Total Take & Pay | 77,962 | 81,650 | 82,976 | 84,019 | 85,300 | 86,841 |
| Take or Pay Contracts | | | | | | |
| Ocean State | 73,210 | 80,280 | 79,811 | 79,934 | 75,430 | 75,945 |
| Connecticut Yankee | 25,027 | 30,586 | 32,773 | 28,147 | 34,855 | 30,717 |
| Maine Yankee | 26,263 | 34,408 | 36,189 | 30,255 | 40,480 | 42,924 |
| Vermont Yankee | 25,210 | 30,310 | 31,564 | 28,328 | 33,188 | 31,129 |
| Canal 1 | 6,946 | 10,647 | 12,000 | 10,731 | 11,494 | 15,694 |
| Middletown 4 (repl. Mt Tom) | 3,028 | 2,167 | | | | |
| NIMO-Oswego 4 | 2,260 | 2,339 | | | | |
| NU Slice Purchase | 28,484 | 28,454 | 14,407 | 7,524 | 6,278 | |
| Total Take or Pay | 190,428 | 219,190 | 206,743 | 184,918 | 201,724 | 196,409 |
| Total Take & Pay and Take or Pay | 268,390 | 300,840 | 289,720 | 268,937 | 287,024 | 283,250 |
| Sales & Brokered Contracts | | | | | | |
| Salem Harbor 4 to Newport | 525 | 521 | | | | |
| Brayton Point 4 to Newport | 610 | 514 | | | | |
| Wyman 4 to Newport | 272 | 229 | | | | |
| Salem Harbor 3 to Unitil | 705 | 705 | 1,151 | 1,692 | 1,861 | 1,818 |
| Millstone 3 to Unitil | 313 | 761 | 1,175 | 1,233 | 1,120 | 1,189 |
| System Slice to Reading Mun. Light Dept. | 1,163 | 2,388 | 2,579 | 2,785 | 3,008 | 2,507 |
| System Slice to Shrewsbury | 1,210 | 1,809 | 2,116 | 2,360 | 2,513 | 2,636 |
| System Slice to Nantucket | | | | 156 | 796 | 1,456 |
| Millstone 3/Seabrook 1 to Bangor | 596 | 450 | 450 | 450 | 450 | 375 |
| Bear Swamp to Central Vermont Public Svc | 210 | 215 | 226 | 226 | 150 | |
| Maine Yankee to Unitil | 78 | 189 | 305 | 383 | 512 | 543 |
| Ocean State to Unitil | 1,223 | 2,813 | 4,302 | 6,463 | 6,099 | 6,141 |
| System Slice to Braintree | 89 | 558 | 607 | 657 | 706 | 756 |
| System Slice to Littleton | 128 | 765 | 780 | 795 | 813 | 828 |
| System Slice to Taunton | | 265 | 1,795 | 2,023 | 2,280 | 2,578 |
| Manchester Street/Bear Swamp to Groton | | 3 | 147 | 147 | 148 | 148 |
| Manchester Street/Bear Swamp to Hingham | | 10 | 587 | 589 | 591 | 593 |
| Manchester Street/Bear Swamp to Holden | | 10 | 587 | 589 | 591 | 593 |
| Manchester Street/Bear Swamp to Middleton | | 3 | 147 | 147 | 148 | 148 |
| Manchester Street/Bear Swamp to North Attleboro | | 20 | 1,175 | 1,178 | 1,182 | 1,185 |
| Total Sales & Brokered Contracts | 7,119 | 12,226 | 18,129 | 21,874 | 22,967 | 23,492 |
| Capacity Exchange | | | | | | |
| Bear Swamp (NEP to Canal Elec) | (2,254) | (2,256) | (2,256) | (752) | | |
| Canal 2 (Com Elec to NEP) | 1,935 | 1,985 | 1,985 | 662 | | |
| Total Exchanges | (320) | (271) | (271) | (90) | 0 | 0 |
| Net Fixed Charges | 260,950 | 288,343 | 271,320 | 246,973 | 264,057 | 259,758 |

| Total Payment | 1994 Actual Estimated | Projected Total Payment 1995 | 1996 | 1997 | 1998 | 1999 |
|---|---|---|---|---|---|---|
| **Take & Pay Contracts** | | | | | | |
| Lawrence Hydro | 4,893 | 4,977 | 4,913 | 4,847 | 4,777 | 4,698 |
| Mascoma Hydro | 346 | 349 | 349 | 349 | 349 | 247 |
| Pontook | 4,934 | 5,099 | 5,099 | 5,099 | 5,099 | 5,099 |
| Northeast Landfill | 4,102 | 4,196 | 4,284 | 4,351 | 4,431 | 4,515 |
| Turnkey, Rochester NH | 1,331 | 1,351 | 1,374 | 1,391 | 1,412 | 1,433 |
| Ogden Haverhill | 27,254 | 28,412 | 28,918 | 29,278 | 29,731 | 30,197 |
| Resco-Saugus | 18,567 | 19,257 | 19,568 | 20,014 | 20,290 | 20,574 |
| Resco-N. Andover | 4,422 | 5,501 | 5,763 | 5,918 | 6,462 | 7,152 |
| Signal-Millbury | 28,953 | 28,667 | 29,173 | 29,533 | 29,986 | 30,452 |
| Barre Landfill | | 109 | 285 | 289 | 294 | 299 |
| Genesis Landfill - Johnston | | | 289 | 500 | 506 | 512 |
| Nashua Landfill | | | 304 | 303 | 303 | 303 |
| Plainville Landfill | | | 340 | 590 | 600 | 609 |
| Randolph Landfill | | | 387 | 662 | 662 | 662 |
| TIRU - Shirley | | | | 731 | 1,254 | 1,254 |
| NEP Windplant 1 phase I | | | | 478 | 878 | 935 |
| NEP Windplant 1 phase II | | | | | 128 | 234 |
| NEP Windplant 1 phase III | | | | | | 702 |
| Altresco | 52,155 | 50,387 | 51,251 | 51,844 | 52,758 | 53,857 |
| Clark University | 11 | 3 | 3 | 3 | 4 | 4 |
| Enron | 17,089 | 18,626 | 19,565 | 20,530 | 21,553 | 22,627 |
| Pawtucket (Colfax) EMI | 26,569 | 30,657 | 30,979 | 31,360 | 32,002 | 32,250 |
| Total Take & Pay | 190,625 | 197,589 | 202,845 | 208,071 | 213,476 | 218,615 |
| **Take or Pay Contracts** | | | | | | |
| Ocean State | 92,546 | 101,793 | 101,212 | 102,440 | 99,791 | 102,363 |
| Connecticut Yankee | 29,353 | 34,475 | 35,778 | 30,975 | 37,978 | 34,547 |
| Maine Yankee | 31,226 | 38,310 | 40,176 | 34,347 | 44,886 | 48,380 |
| Vermont Yankee | 29,267 | 33,733 | 35,107 | 31,931 | 37,151 | 35,152 |
| Canal 1 | 21,185 | 30,505 | 34,236 | 34,025 | 35,959 | 41,311 |
| Middletown 4 (repl. Mt Tom) | 3,726 | 4,212 | | | | |
| NIMO-Oswego 4 | 6,727 | 3,433 | | | | |
| NU Slice Purchase | 32,212 | 31,003 | 15,283 | 7,881 | 6,768 | |
| Total Take or Pay | 246,242 | 277,463 | 261,791 | 241,598 | 262,534 | 261,752 |
| Total Take & Pay and Take or Pay | 436,866 | 475,053 | 464,636 | 449,669 | 476,010 | 480,367 |
| **Sales & Brokered Contracts** | | | | | | |
| Salem Harbor 4 to Newport | 839 | 610 | | | | |
| Brayton Point 4 to Newport | 883 | 852 | | | | |
| Wyman 4 to Newport | 362 | 306 | | | | |
| Salem Harbor 3 to Unitil | 1,043 | 1,164 | 1,837 | 2,792 | 2,932 | 2,949 |
| Millstone 3 to Unitil | 339 | 801 | 1,235 | 1,298 | 1,188 | 1,258 |
| System Slice to Reading Mun. Light Dept. | 2,236 | 5,039 | 5,350 | 5,657 | 5,966 | 5,046 |
| System Slice to Shrewsbury | 2,676 | 3,389 | 4,030 | 4,352 | 4,583 | 4,765 |
| System Slice to Nantucket | | | | 3,315 | 4,142 | 5,005 |
| Millstone 3/Seabrook 1 to Bangor | 5,053 | 5,454 | 5,222 | 5,391 | 5,937 | 5,526 |
| Bear Swamp to Central Vermont Public Svc | 210 | 215 | 226 | 226 | 150 | |
| Maine Yankee to Unitil | 93 | 210 | 339 | 435 | 568 | 612 |
| Ocean State to Unitil | 2,327 | 3,567 | 5,456 | 8,283 | 8,069 | 8,277 |
| System Slice to Braintree | 117 | 781 | 837 | 893 | 950 | 1,007 |
| System Slice to Littleton | 182 | 1,100 | 1,125 | 1,150 | 1,179 | 1,205 |
| System Slice to Taunton | | 450 | 2,944 | 3,206 | 3,499 | 3,833 |
| Manchester Street/Bear Swamp to Groton | | 7 | 209 | 211 | 213 | 216 |
| Manchester Street/Bear Swamp to Hingham | | 28 | 835 | 843 | 852 | 862 |
| Manchester Street/Bear Swamp to Holden | | 28 | 835 | 843 | 852 | 862 |
| Manchester Street/Bear Swamp to Middleton | | 7 | 209 | 211 | 213 | 216 |
| Manchester Street/Bear Swamp to North Attleboro | | 56 | 1,669 | 1,686 | 1,704 | 1,725 |
| Total Sales & Brokered Contracts | 16,359 | 24,062 | 32,355 | 40,789 | 42,996 | 43,362 |
| **Capacity Exchange** | | | | | | |
| Bear Swamp (NEP to Com Elec) | (2,254) | (2,256) | (2,256) | (752) | | |
| Canal 2 (Com Elec to NEP) | 5,718 | 4,885 | 4,241 | 1,524 | | |
| Total Exchanges | 3,464 | 2,629 | 1,985 | 772 | 0 | 0 |
| Net Total Payment | 423,971 | 453,620 | 434,267 | 409,651 | 433,014 | 437,006 |

| MWH Available | 1994 Actual Estimated | Projected MWH Available 1995 | 1996 | 1997 | 1998 | 1999 |
|---|---|---|---|---|---|---|
| Take & Pay Contracts | | | | | | |
| Lawrence Hydro | 68,204 | 70,142 | 70,142 | 70,142 | 70,142 | 70,142 |
| Mascoma Hydro | 4,065 | 4,100 | 4,111 | 4,100 | 4,100 | 4,100 |
| Pontook | 61,677 | 63,738 | 63,738 | 63,738 | 63,738 | 63,738 |
| Northeast Landfill | 68,040 | 68,328 | 68,515 | 68,328 | 68,328 | 68,328 |
| Turnkey, Rochester NH | 23,654 | 23,652 | 23,717 | 23,652 | 23,652 | 23,652 |
| Ogden Haverhill | 306,229 | 315,455 | 316,319 | 315,455 | 315,455 | 315,455 |
| Resco-Saugus | 232,571 | 237,529 | 238,180 | 240,357 | 240,357 | 240,357 |
| Resco-N. Andover | 233,414 | 210,109 | 233,157 | 232,520 | 232,520 | 232,520 |
| Signal-Millbury | 326,696 | 321,115 | 321,995 | 321,115 | 321,115 | 321,115 |
| Barre Landfill | | 1,840 | 4,743 | 4,730 | 4,730 | 4,730 |
| Genesis Landfill - Johnston | | | 4,796 | 8,199 | 8,199 | 8,199 |
| Nashua Landfill | | | 6,404 | 6,386 | 6,386 | 6,386 |
| Plainville Landfill | | | 7,840 | 13,403 | 13,403 | 13,403 |
| Randolph Landfill | | | 7,305 | 12,488 | 12,488 | 12,488 |
| TIRU - Shirley | | | | 14,062 | 24,106 | 24,106 |
| NEP Windplant 1 phase I | | | | 11,191 | 19,184 | 19,184 |
| NEP Windplant 1 phase II | | | | | 2,798 | 4,796 |
| NEP Windplant 1 phase III | | | | | | 14,388 |
| Altresco | 827,597 | 861,660 | 864,161 | 861,660 | 861,660 | 861,660 |
| Clark University | 619 | 157 | 158 | 157 | 157 | 157 |
| Enron | 487,525 | 657,841 | 659,643 | 657,841 | 657,841 | 657,841 |
| Pawtucket (Colfax) EMI | 400,241 | 519,728 | 521,163 | 519,728 | 519,728 | 519,728 |
| Total Take & Pay | 3,040,532 | 3,355,393 | 3,416,086 | 3,449,252 | 3,470,088 | 3,486,475 |
| Take or Pay Contracts | | | | | | |
| Ocean State | 1,991,996 | 1,931,492 | 1,931,492 | 1,931,492 | 1,931,492 | 1,931,492 |
| Connecticut Yankee | 570,252 | 559,545 | 559,545 | 559,545 | 559,545 | 559,545 |
| Maine Yankee | 1,189,264 | 1,003,344 | 998,228 | 998,228 | 998,228 | 998,228 |
| Vermont Yankee | 776,018 | 600,472 | 600,472 | 600,472 | 600,472 | 600,472 |
| Canal 1 | 648,612 | 915,000 | 915,000 | 915,000 | 915,000 | 915,000 |
| Middletown 4 (repl. Mt Tom) | 18,778 | 72,078 | | | | |
| NIMO-Oswego 4 | 201,840 | 36,882 | | | | |
| NU Slice Purchase | 440,197 | 400,203 | 213,098 | 93,580 | 95,271 | |
| Total Take or Pay | 5,836,956 | 5,519,016 | 5,217,835 | 5,098,317 | 5,100,008 | 5,004,737 |
| Total Take & Pay and Take or Pay | 8,877,488 | 8,874,409 | 8,633,921 | 8,547,570 | 8,570,096 | 8,491,212 |
| Sales & Brokered Contracts | | | | | | |
| Salem Harbor 4 to Newport | (13,624) | (3,283) | | | | |
| Brayton Point 4 to Newport | (11,649) | (15,110) | | | | |
| Wyman 4 to Newport | (3,651) | (2,668) | | | | |
| Salem Harbor 3 to Unitil | (19,126) | (30,267) | (45,684) | (73,080) | (70,647) | (73,554) |
| Millstone 3 to Unitil | (5,814) | (8,332) | (12,857) | (12,822) | (12,822) | (12,822) |
| System Slice to Reading Mun. Light Dept. | (50,347) | (111,690) | (111,690) | (111,690) | (111,690) | (93,075) |
| System Slice to Shrewsbury | (84,535) | (84,530) | (93,290) | (95,220) | (95,220) | (96,940) |
| System Slice to Nantucket | | | | (102,702) | (105,020) | (107,642) |
| Millstone 3/Seabrook 1 to Bangor | (212,895) | (210,240) | (210,816) | (210,240) | (210,240) | (192,720) |
| Bear Swamp to Central Vermont Public Svc | 0 | (6,430) | (6,950) | (8,171) | (2,873) | |
| Maine Yankee to Unitil | (3,527) | (5,503) | (8,426) | (12,633) | (12,633) | (12,633) |
| Ocean State to Unitil | (46,476) | (67,435) | (104,101) | (156,176) | (156,176) | (156,176) |
| System Slice to Braintree | (1,870) | (14,016) | (14,016) | (14,016) | (14,016) | (14,016) |
| System Slice to Littleton | (3,525) | (21,024) | (21,024) | (21,024) | (21,024) | (21,024) |
| System Slice to Taunton | | (11,680) | (70,080) | (70,080) | (70,080) | (70,080) |
| Manchester Street/Bear Swamp to Groton | | (274) | (3,285) | (3,285) | (3,285) | (3,285) |
| Manchester Street/Bear Swamp to Hingham | | (1,095) | (13,140) | (13,140) | (13,140) | (13,140) |
| Manchester Street/Bear Swamp to Holden | | (1,095) | (13,140) | (13,140) | (13,140) | (13,140) |
| Manchester Street/Bear Swamp to Middleton | | (274) | (3,285) | (3,285) | (3,285) | (3,285) |
| Manchester Street/Bear Swamp to North Attleboro | | (2,190) | (26,280) | (26,280) | (26,280) | (26,280) |
| Total Sales & Brokered Contracts | (457,039) | (597,136) | (758,065) | (946,984) | (941,572) | (909,813) |
| Capacity Exchange | | | | | | |
| Bear Swamp (NEP to Com Elec) | 0 | (38,439) | (41,547) | (16,282) | | |
| Canal 2 (Com Elec to NEP) | 14,089 | 122,832 | 86,703 | 31,536 | | |
| Net Capacity Exchange | 14,089 | 84,393 | 45,156 | 15,254 | 0 | 0 |
| Total Take & Pay and Take or Pay (MWh) | 8,877,488 | 8,874,409 | 8,633,921 | 8,547,570 | 8,570,096 | 8,491,212 |
| Total Sales & Brokered/Net Capacity Exchange (MWh) | (442,950) | (512,743) | (712,909) | (931,730) | (941,572) | (909,813) |
| Total all Transactions (MWh) | 8,434,538 | 8,361,666 | 7,921,013 | 7,615,840 | 7,628,525 | 7,581,399 |

| MWH Dispatched | 1994 Actual Estimated | Projected MWH Dispatched 1995 | 1996 | 1997 | 1998 | 1999 |
|---|---|---|---|---|---|---|
| Take & Pay Contracts | | | | | | |
| Lawrence Hydro | 68,204 | 70,142 | 70,142 | 70,142 | 70,142 | 70,142 |
| Mascoma Hydro | 4,065 | 4,100 | 4,111 | 4,100 | 4,100 | 4,100 |
| Pontook | 61,677 | 63,738 | 63,738 | 63,738 | 63,738 | 63,738 |
| Northeast Landfill | 68,040 | 68,328 | 68,515 | 68,328 | 68,328 | 68,328 |
| Turnkey, Rochester NH | 23,654 | 23,652 | 23,717 | 23,652 | 23,652 | 23,652 |
| Ogden Haverhill | 306,229 | 315,455 | 316,319 | 315,455 | 315,455 | 315,455 |
| Resco-Saugus | 232,571 | 237,529 | 238,180 | 240,357 | 240,357 | 240,357 |
| Resco-N. Andover | 233,414 | 210,109 | 233,157 | 232,520 | 232,520 | 232,520 |
| Signal-Millbury | 326,696 | 321,115 | 321,995 | 321,115 | 321,115 | 321,115 |
| Barre Landfill | | 1,840 | 4,743 | 4,730 | 4,730 | 4,730 |
| Genesis Landfill - Johnston | | | 4,796 | 8,199 | 8,199 | 8,199 |
| Nashua Landfill | | | 6,404 | 6,386 | 6,386 | 6,386 |
| Plainville Landfill | | | 7,840 | 13,403 | 13,403 | 13,403 |
| Randolph Landfill | | | 7,305 | 12,488 | 12,488 | 12,488 |
| TIRU - Shirley | | | | 14,062 | 24,106 | 24,106 |
| NEP Windplant 1 phase I | | | | 11,191 | 19,184 | 19,184 |
| NEP Windplant 1 phase II | | | | | 2,798 | 4,796 |
| NEP Windplant 1 phase III | | | | | | 14,388 |
| Altresco | 827,597 | 706,970 | 664,603 | 667,044 | 669,365 | 670,386 |
| Clark University | 619 | 157 | 158 | 157 | 157 | 157 |
| Enron | 487,525 | 481,869 | 470,787 | 299,515 | 318,724 | 353,853 |
| Pawtucket (Colfax) EMI | 400,241 | 399,743 | 422,926 | 442,886 | 471,276 | 464,626 |
| Total Take & Pay | 3,040,532 | 2,904,746 | 2,929,436 | 2,819,469 | 2,890,224 | 2,936,110 |
| Take or Pay Contracts | | | | | | |
| Ocean State | 1,991,996 | 1,931,492 | 1,931,492 | 1,931,492 | 1,931,492 | 1,931,492 |
| Connecticut Yankee | 570,252 | 559,545 | 559,545 | 559,545 | 559,545 | 559,545 |
| Maine Yankee | 1,189,264 | 1,003,344 | 998,228 | 998,228 | 998,228 | 998,228 |
| Vermont Yankee | 776,018 | 600,472 | 600,472 | 600,472 | 600,472 | 600,472 |
| Canal 1 | 648,612 | 915,000 | 915,000 | 915,000 | 915,000 | 915,000 |
| Middletown 4 (repl. Mt Tom) | 18,778 | 72,078 | | | | |
| NIMO-Oswego 4 | 201,840 | 36,882 | | | | |
| NU Slice Purchase | 440,197 | 400,203 | 213,098 | 93,580 | 95,271 | |
| Total Take or Pay | 5,836,956 | 5,519,016 | 5,217,835 | 5,098,317 | 5,100,008 | 5,004,737 |
| Total Take & Pay and Take or Pay | 8,877,488 | 8,423,762 | 8,147,271 | 7,917,786 | 7,990,232 | 7,940,848 |
| Sales & Brokered Contracts | | | | | | |
| Salem Harbor 4 to Newport | (13,624) | (3,283) | | | | |
| Brayton Point 4 to Newport | (11,649) | (15,110) | | | | |
| Wyman 4 to Newport | (3,651) | (2,668) | | | | |
| Salem Harbor 3 to Unitil | (19,126) | (30,267) | (45,684) | (73,080) | (70,647) | (73,554) |
| Millstone 3 to Unitil | (5,814) | (8,332) | (12,857) | (12,822) | (12,822) | (12,822) |
| System Slice to Reading Mun. Light Dept. | (50,347) | (111,690) | (111,690) | (111,690) | (111,690) | (93,075) |
| System Slice to Shrewsbury | (84,535) | (84,530) | (93,290) | (95,220) | (95,220) | (96,940) |
| System Slice to Nantucket | | | | (102,702) | (105,020) | (107,642) |
| Millstone 3/Seabrook 1 to Bangor | (212,895) | (210,240) | (210,816) | (210,240) | (210,240) | (192,720) |
| Bear Swamp to Central Vermont Public Svc | 0 | (6,430) | (6,950) | (8,171) | (2,873) | |
| Maine Yankee to Unitil | (3,527) | (5,503) | (8,426) | (12,633) | (12,633) | (12,633) |
| Ocean State to Unitil | (46,476) | (67,435) | (104,101) | (156,176) | (156,176) | (156,176) |
| System Slice to Braintree | (1,870) | (14,016) | (14,016) | (14,016) | (14,016) | (14,016) |
| System Slice to Littleton | (3,525) | (21,024) | (21,024) | (21,024) | (21,024) | (21,024) |
| System Slice to Taunton | | (11,680) | (70,080) | (70,080) | (70,080) | (70,080) |
| Manchester Street/Bear Swamp to Groton | | (274) | (3,285) | (3,285) | (3,285) | (3,285) |
| Manchester Street/Bear Swamp to Hingham | | (1,095) | (13,140) | (13,140) | (13,140) | (13,140) |
| Manchester Street/Bear Swamp to Holden | | (1,095) | (13,140) | (13,140) | (13,140) | (13,140) |
| Manchester Street/Bear Swamp to Middleton | | (274) | (3,285) | (3,285) | (3,285) | (3,285) |
| Manchester Street/Bear Swamp to North Attleboro | | (2,190) | (26,280) | (26,280) | (26,280) | (26,280) |
| Total Sales & Brokered Contracts | (457,039) | (597,136) | (758,065) | (946,984) | (941,572) | (909,813) |
| Capacity Exchange | | | | | | |
| Bear Swamp (NEP to Com Elec) | 0 | (38,439) | (41,547) | (16,282) | | |
| Canal 2 (Com Elec to NEP) | 14,089 | 122,832 | 86,703 | 31,536 | | |
| Net Capacity Exchange | 14,089 | 84,393 | 45,156 | 15,254 | 0 | 0 |
| Total Take & Pay and Take or Pay (MWh) | 8,877,488 | 8,423,762 | 8,147,271 | 7,917,786 | 7,990,232 | 7,940,848 |
| Total Sales & Brokered/Net Capacity Exchange (MWh) | (442,950) | (512,743) | (712,909) | (931,730) | (941,572) | (909,813) |
| Total all Transactions (MWh) | 8,434,538 | 7,911,019 | 7,434,363 | 6,986,056 | 7,048,661 | 7,031,035 |

| Price Per KWH | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 |
|---|---|---|---|---|---|---|
| Take & Pay Contracts | | | | | | |
| Lawrence Hydro | 7.17 | 7.10 | 7.00 | 6.91 | 6.81 | 6.70 |
| Mascoma Hydro | 8.51 | 8.50 | 8.50 | 8.50 | 8.50 | 6.03 |
| Pontook | 8.00 | 8.00 | 8.00 | 8.00 | 8.00 | 8.00 |
| Northeast Landfill | 6.03 | 6.14 | 6.25 | 6.37 | 6.49 | 6.61 |
| Turnkey, Rochester NH | 5.63 | 5.71 | 5.80 | 5.88 | 5.97 | 6.06 |
| Ogden Haverhill | 8.90 | 9.01 | 9.14 | 9.28 | 9.42 | 9.57 |
| Resco-Saugus | 7.98 | 8.11 | 8.22 | 8.33 | 8.44 | 8.56 |
| Resco-N. Andover | 1.89 | 2.62 | 2.47 | 2.55 | 2.78 | 3.08 |
| Signal-Millbury | 8.86 | 8.93 | 9.06 | 9.20 | 9.34 | 9.48 |
| Barre Landfill | | 5.90 | 6.00 | 6.11 | 6.22 | 6.33 |
| Genesis Landfill - Johnston | | | 6.02 | 6.09 | 6.17 | 6.24 |
| Nashua Landfill | | | 4.75 | 4.75 | 4.75 | 4.75 |
| Plainville Landfill | | | 4.34 | 4.41 | 4.48 | 4.55 |
| Randolph Landfill | | | 5.30 | 5.30 | 5.30 | 5.30 |
| TIRU - Shirley | | | | 5.20 | 5.20 | 5.20 |
| NEP Windplant 1 phase I | | | | 4.27 | 4.57 | 4.88 |
| NEP Windplant 1 phase II | | | | | 4.57 | 4.88 |
| NEP Windplant 1 phase III | | | | | | 4.88 |
| Altresco | 6.30 | 7.13 | 7.71 | 7.77 | 7.88 | 8.03 |
| Clark University | 1.75 | 2.14 | 2.04 | 2.11 | 2.35 | 2.65 |
| Enron | 3.51 | 3.87 | 4.16 | 6.85 | 6.76 | 6.39 |
| Pawtucket (Colfax) EMI | 6.64 | 7.67 | 7.32 | 7.08 | 6.79 | 6.94 |
| Take or Pay Contracts | | | | | | |
| Ocean State | 4.65 | 5.27 | 5.24 | 5.30 | 5.17 | 5.30 |
| Connecticut Yankee | 5.15 | 6.16 | 6.39 | 5.54 | 6.79 | 6.17 |
| Maine Yankee | 2.63 | 3.82 | 4.02 | 3.44 | 4.50 | 4.85 |
| Vermont Yankee | 3.77 | 5.62 | 5.85 | 5.32 | 6.19 | 5.85 |
| Canal 1 | 3.27 | 3.33 | 3.74 | 3.72 | 3.93 | 4.51 |
| Middletown 4 (repl. Mt Tom) | 19.84 | 5.84 | | | | |
| NIMO-Oswego 4 | 3.33 | 9.31 | | | | |
| NU Slice Purchase | 7.32 | 7.75 | 7.17 | 8.42 | 7.10 | |
| Sales & Brokered Contracts | | | | | | |
| Salem Harbor 4 to Newport | -6.16 | -18.57 | | | | |
| Brayton Point 4 to Newport | -7.58 | -5.64 | | | | |
| Wyman 4 to Newport | -9.90 | -11.47 | | | | |
| Salem Harbor 3 to Unitil | -5.45 | -3.85 | -4.02 | -3.82 | -4.15 | -4.01 |
| Millstone 3 to Unitil | -5.83 | -9.61 | -9.61 | -10.12 | -9.26 | -9.81 |
| System Slice to Reading Mun. Light Dept. | -4.44 | -4.51 | -4.79 | -5.07 | -5.34 | -5.42 |
| System Slice to Shrewsbury | -3.17 | -4.01 | -4.32 | -4.57 | -4.81 | -4.92 |
| System Slice to Nantucket | | | | -3.23 | -3.94 | -4.65 |
| Millstone 3/Seabrook 1 to Bangor | -2.37 | -2.59 | -2.48 | -2.56 | -2.82 | -2.87 |
| Bear Swamp to Central Vermont Public Svc | | -3.35 | -3.25 | -2.76 | -5.23 | |
| Maine Yankee to Unitil | -2.63 | -3.82 | -4.02 | -3.44 | -4.50 | -4.85 |
| Ocean State to Unitil | -5.01 | -5.29 | -5.24 | -5.30 | -5.17 | -5.30 |
| System Slice to Braintree | -6.28 | -5.57 | -5.97 | -6.37 | -6.78 | -7.18 |
| System Slice to Littleton | -5.16 | -5.23 | -5.35 | -5.47 | -5.61 | -5.73 |
| System Slice to Taunton | | -3.86 | -4.20 | -4.57 | -4.99 | -5.47 |
| Manchester Street/Bear Swamp to Groton | | -2.54 | -6.35 | -6.41 | -6.49 | -6.56 |
| Manchester Street/Bear Swamp to Hingham | | -2.54 | -6.35 | -6.41 | -6.49 | -6.56 |
| Manchester Street/Bear Swamp to Holden | | -2.54 | -6.35 | -6.41 | -6.49 | -6.56 |
| Manchester Street/Bear Swamp to Middleton | | -2.72 | -6.35 | -6.41 | -6.49 | -6.56 |
| Manchester Street/Bear Swamp to North Attleboro | | -2.54 | -6.35 | -6.41 | -6.49 | -6.56 |
| Capacity Exchange | | | | | | |
| Bear Swamp (NEP to Com Elec) | | -5.87 | -5.43 | -4.62 | | |
| Canal 2 (Com Elec to NEP) | 40.59 | 3.98 | 4.89 | 4.83 | | |

| Average Prices | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 |
|---|---|---|---|---|---|---|
| Avg Price/KWH T&P | 6.27 | 6.80 | 6.92 | 7.38 | 7.39 | 7.45 |
| Avg Price/KWH TorP | 4.22 | 5.03 | 5.02 | 4.74 | 5.15 | 5.23 |
| Avg Price/KWH T&P and TorP | 4.92 | 5.64 | 5.70 | 5.68 | 5.96 | 6.05 |
| Avg Price/KWH all Sales & Brokered and Net Capacity Exchange | -4.48 | -5.21 | -4.82 | -4.46 | -4.57 | -4.77 |
| Avg Price/KWH all Transactions | 5.03 | 5.73 | 5.84 | 5.86 | 6.14 | 6.22 |

Exhibit ____ AG-PLC-4



Dates of Commitment and Operation for NEPCo NUG Purchases
(in reverse order of commitment)

| Project | Summer Capacity (MW)[1] | Cumulative Excess Capacity (MW) | Contract Date[2] | First Listed as "Planned" in Resource Plan[3] | In-Service Date[1] |
|---|---|---|---|---|---|
| Mass Power (Monsanto) | 13 | 13 | | | Nov-94 |
| Enron (Milford) | 83 | 96 | | Aug '91 | Jul '93 |
| Manchester St.[4] | 304 | 400 | | May '89 | |
| Ocean States Power 1 | 115 | 515 | | May '89 | Jan '91 |
| Ocean States Power 2 | 115 | 630 | | May '89 | Oct '91 |
| L'Energia | 13 | 643 | Jul '88 | | Mar '93 |
| Pawtucket Power | 63 | 706 | Dec '87 | | Feb '91 |
| Altresco Pittsfield | 93 | 799 | Dec '87 | | Sep '90 |
| Northeast Landfill | 10 | 809 | Nov '87 | | Feb '90 |
| Ogden Martin | 40 | 849 | Dec '85 | | Jun '89 |

Notes:

1 From NEPLAN CELT Report, Appendix B.2, April 1, 1995; except Enron, from 1994 CELT Report, and Manchester Street, from 1994 IRP. Capabilities have been rounded to the nearest whole number.

2 Alternate Energy Negotiating-Bidding Experiment 1989 Report

3 These resources may have been committed in the 1988 resource plan, which was unavailable.

4 Capacity is the difference between the 1996 and 1994 capacities: 432 MW -128 MW.

Exhibit____(AG-PLC-5)
Summary of NEES and MECo Actual Loads
(GWh)

Exhibit____(AG-PLC-5)

NEES

| | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Res | 6,460 | 6,813 | 7,268 | 7,766 | 7,952 | 7,926 | 7,906 | 8,023 | 8,123 | 8,253 | 8,154 |
| Com | 5,805 | 6,195 | 6,672 | 7,096 | 7,419 | 7,545 | 7,436 | 7,496 | 7,691 | 7,894 | 7,941 |
| Ind | 4,623 | 4,761 | 4,865 | 5,064 | 5,109 | 5,074 | 4,950 | 4,874 | 4,860 | 4,859 | 4,948 |
| Total | 16,888 | 17,769 | 18,805 | 19,926 | 20,480 | 20,545 | 20,292 | 20,393 | 20,674 | 21,006 | 21,043 |

MECo

| | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Res | 4,783 | 5,050 | 5,397 | 5,783 | 5,922 | 5,892 | 5,888 | 6,000 | 6,066 | 6,171 | 6,079 |
| Com | 4,130 | 4,430 | 4,786 | 5,079 | 5,329 | 5,387 | 5,266 | 5,291 | 5,432 | 5,628 | 5,559 |
| Ind | 3,734 | 3,857 | 3,946 | 4,139 | 4,169 | 4,114 | 3,975 | 3,910 | 3,847 | 3,885 | 3,912 |
| Total | 12,647 | 13,337 | 14,129 | 15,001 | 15,420 | 15,393 | 15,129 | 15,201 | 15,345 | 15,684 | 15,550 |

Notes: Sales include C&LM.
Total equals sum of residential, commercial and industrial sales.
Data for 1995 is projected from 1994.
1994 residential and commercial actuals adjusted by the difference between 1993 reported actuals from 1994 IRP and NEES Shareholder Services.

Sources: MECo Integrated Resource Plans, 1991 and 1994.
1994 actuals from NEES Shareholder Services.

Exhibit ____AG-PLC-5
Demand-Related Costs of Excess Capacity

*Table 1: Computation of Generic Excess Capacity Costs*

| | For a gas turbine installed at the start of 2001 | | For a gas turbine installed in or before 1996 | |
|---|---|---|---|---|
| Year of Operation | Revenue Requirement ($1,000s) [1] | Revenue Requirement ($/kWyr) [2] | In-Service Date for Which Year of Operation is 1996 [3] | Revenue Requirement in 1996 ($/kWyr) [4] |
| 1 | $23,060 | $136 | 1996 | $118 |
| 2 | $22,823 | $135 | 1995 | $113 |
| 3 | $22,311 | $132 | 1994 | $107 |
| 4 | $21,835 | $129 | 1993 | $102 |
| 5 | $21,388 | $127 | 1992 | $97 |
| 6 | $20,972 | $124 | 1991 | $92 |
| 7 | $20,586 | $122 | 1990 | $88 |
| 8 | $20,226 | $120 | 1989 | $84 |

Notes:

[1]: From Workpaper NE-BL-2, page 1 in FERC Docket No. W-95 (December 1994). This is the revenue requirement in the given Year of Operation for a 169 MW gas turbine installed in 2001.

[2]: [1]÷169 MW

[3]: E.g., 1996 is the 7th year of operation for a plant coming into service at the start of 1990.

[4]: [2], deflated to 1996 from year of operation following 2001 installation, at 3% inflation, as specified in Workpaper NE-BL-2.

# Exhibit ____ AG-PLC-6
## Demand-Related Costs of Excess Capacity

*Table 2: Computation of NEPCo's Excess Capacity Costs*

| In-Service Date [1] | Summer Normal Capacity (MW) [2] | Peaking Gas Turbine Cost in 1996 ($/kWyr) [3] | Total 1995 Revenue Requirement for GT's of Equal Capacity and Age ($1,000s) [4] | Resources [5] |
|---|---|---|---|---|
| 1996 | 304 | $118 | $35,782 | Manchester St. (432 MW - 128 MW) |
| 1995 | | 113 | - | |
| 1994 | 13 | 107 | 1,395 | Mass Power |
| 1993 | 96 | 102 | 9,791 | Enron (83), L'Energia (13) |
| 1992 | | 97 | - | |
| 1991 | 293 | 92 | 27,055 | Pawtucket (63 MW), OSP 1&2 (230 MW) |
| 1990 | 103 | 88 | 9,064 | Altresco (93 MW), NE Landfill (10) |
| 1989 | 40 | 84 | 3,358 | Ogden Martin (40) |
| **Total** | **849** | | **$86,445** | |

Column Notes:
[2]: See Exhibit ____ AG-PLC-4.
[3]: See Exhibit ____AG-PLC-6, Table 1, Column [4].
[4]: [2]×[3]
[5]: Resources were assigned to on-line dates on the basis of the 1995 CELT.

Exhibit ____ AG-PLC-7
Unutilized Available Generation in Other NEPCo Plants

| | Projected 1995 Generation (MWh) [1] | Capacity Factor with Maintenance [2] | Implied Capacity (MW) [3] | EAF [4] | One-Unit Sales (MWh) [5] | Total Potential Generation (MWh) [6] | Unused Potential Generation (MWh) [7] |
|---|---|---|---|---|---|---|---|
| BP-1 | 1,742,427 | 84.28% | 236.01 | 87.67% | 12,059 | 1,812,444 | 57,958 |
| BP-2 | 1,868,503 | 87.06% | 245.00 | 87.66% | | 1,881,345 | 12,842 |
| BP-3 | 3,337,910 | 65.14% | 584.96 | 65.57% | | 3,359,773 | 21,863 |
| BP-4 | 1,325,314 | 35.51% | 426.05 | 86.01% | | 3,210,027 | 1,884,713 |
| SH-1 | 549,808 | 77.49% | 81.00 | 92.63% | | 657,253 | 107,445 |
| SH-2 | 399,523 | 58.47% | 78.00 | 92.89% | | 634,725 | 235,202 |
| SH-3 | 1,008,836 | 82.88% | 138.95 | 92.70% | 32,886 | 1,128,367 | 86,645 |
| SH-4 | 1,235,114 | 35.64% | 395.61 | 73.11% | 11,191 | 2,533,589 | 1,287,284 |
| Canal-1 | 717,778 | 57.58% | 142.30 | 74.71% | | 931,296 | 213,518 |
| Canal-2 | 172,245 | 39.48% | 49.80 | 91.65% | | 399,854 | 227,609 |
| Wyman 4 | 128,586 | 27.86% | 52.69 | 85.05% | 5,343 | 392,543 | 258,614 |
| **Total** | | | | | | | **4,393,693** |

Notes:

W-95 Workpapers of C.O. Paradise, pages 60 & 61, cited below, are attached as pages 2 & 3 of this Exhibit.

[1]: W-95 Workpapers of C.O. Paradise, page 60.1995 Month 13 Total MWh.

[2]: W-95 Workpapers of C.O. Paradise, page 60. 1995 Month 13 Capacity Factor with Maintenance.

[3]: [1]÷([2]×8760)

[4]: Averages of the monthly EAFs consistent with the dispatch runs output in the W-95 Workpapers of C.O. Paradise, as provided in response to AG-15-7 in MDPU 95-40.

[5]: W-95 Workpapers of C.O. Paradise, pages 60-1. It is not clear whether the on-unit sales are include in the total generation in column [1].

[6]: [3]×[4]×8760

[7]: [6]-[1]-[5]. This figure is understated if the one-unit sales in column [5] are included in the total MWh in column [1].

PAGE 16 MONTH 13 YEAR 1995 ****** NEES ESTIMATED POWER SUPPLY ****** 27-JUN-94 13:29

| UNIT | TOTAL MWH | TOTAL MBTU | TOTAL DOLLARS | CENTS/ MBTU | MILLS/ KWH | BTU/ KWH | HOURS ON LN | CAP FACTR W/O MAINT | CAP FACTR W/ MAINT |
|---|---|---|---|---|---|---|---|---|---|
| ******** | ********* | ********** | ********** | ******* | ****** | ****** | ***** | ********* | ********* |
| 1 BP-1 | 1742427. | 17111758. | 28894672. | 168.859 | 16.583 | 9821. | 7476 | 0.8641 | 0.8428 |
| 2 BP-2 | 1868503. | 17728820. | 29944932. | 168.905 | 16.026 | 9488. | 7679 | 0.8926 | 0.8706 |
| 3 BP-3 | 3337910. | 30036926. | 50754396. | 168.973 | 15.205 | 8999. | 5707 | 0.8114 | 0.6514 |
| 4 BP-4 | 1325314. | 14170589. | 30533120. | 215.468 | 23.038 | 10692. | 3967 | 0.3641 | 0.3551 |
| 5 SH-1 | 549808. | 5462978. | 8434741. | 154.398 | 15.341 | 9936. | 7035 | 0.7944 | 0.7749 |
| 6 SH-2 | 399523. | 4607477. | 7126415. | 154.671 | 17.837 | 11532. | 6517 | 0.5978 | 0.5847 |
| 7 SH-3 | 1008836. | 9927291. | 15373315. | 154.859 | 15.239 | 9840. | 7330 | 0.8497 | 0.8288 |
| 8 SH-4 | 1235114. | 12969351. | 28011186. | 215.980 | 22.679 | 10501. | 4232 | 0.4130 | 0.3564 |
| 9 Man9CC | 0. | 0. | 0. | 0.000 | 0.000 | 0. | 0 | 0.0000 | 0.0000 |
| 10 Man10CC | 0. | 0. | 0. | 0.000 | 0.000 | 0. | 0 | 0.0000 | 0.0000 |
| 11 Man11CC | 37915. | 317671. | 1005471. | 316.513 | 26.519 | 8378. | 269 | 0.1637 | 0.1637 |
| 12 NU GTS | 7414. | 95961. | 429854. | 447.946 | 57.978 | 12943. | 815 | 0.0930 | 0.0930 |
| 15 NU NUKE | 364752. | 3694574. | 1784479. | 48.300 | 4.892 | 10129. | 7371 | 0.8412 | 0.8412 |
| 16 NU FOSS | 92921. | 958948. | 2357203. | 245.811 | 25.368 | 10320. | 1823 | 0.2080 | 0.2080 |
| 17 BP-DSL | 9565. | 97030. | 395338. | 407.437 | 41.330 | 10144. | 857 | 0.0979 | 0.0979 |
| 18 GL-DSL | 23698. | 239939. | 977650. | 407.458 | 41.255 | 10125. | 895 | 0.1021 | 0.1021 |
| 20 CLARKE | 343. | 3435. | 13466. | 392.013 | 39.201 | 10000. | 858 | 0.0980 | 0.0980 |
| 21 NEW-DSL | 9833. | 98668. | 401794. | 407.217 | 40.860 | 10034. | 936 | 0.1069 | 0.1069 |
| 26 pilgm | 26621. | 270790. | 134962. | 49.840 | 5.070 | 10172. | 5316 | 0.9018 | 0.7297 |
| 27 CO-YK | 561586. | 5913503. | 3712496. | 62.780 | 6.611 | 10530. | 6346 | 0.8813 | 0.7244 |
| 28 VE-YK | 608032. | 6262732. | 3833418. | 61.210 | 6.305 | 10300. | 6511 | 0.8835 | 0.7431 |
| 29 ME-YK | 1036895. | 10902950. | 5230146. | 47.970 | 5.044 | 10515. | 6563 | 0.8957 | 0.7534 |
| 30 CANAL-1 | 717788. | 6510632. | 15309010. | 235.139 | 21.328 | 9070. | 6573 | 0.6846 | 0.5758 |
| 31 MIDD 4 | 114752. | 1261858. | 3152873. | 249.860 | 27.475 | 10996. | 2504 | 0.2679 | 0.2356 |
| 32 CANAL-2 | 172245. | 1686646. | 4025647. | 238.678 | 23.372 | 9792. | 3904 | 0.4048 | 0.3948 |
| 33 Mystic7 | 173291. | 1807243. | 4422443. | 244.707 | 25.520 | 10429. | 5868 | 0.4916 | 0.4431 |
| 39 WYMN-4 | 128586. | 1279499. | 3200596. | 250.144 | 24.891 | 9951. | 2851 | 0.3167 | 0.2786 |
| 43 MILL#3 | 783616. | 7937251. | 4398031. | 55.410 | 5.612 | 10129. | 5590 | 0.8428 | 0.6442 |
| 44 SEAB#1 | 695794. | 7019167. | 3389556. | 48.290 | 4.871 | 10088. | 6078 | 0.8440 | 0.6937 |
| 45 OSP-1 | 943335. | 7958919. | 22284968. | 280.000 | 23.624 | 8437. | 6850 | 0.8105 | 0.8105 |
| 46 OSP-2 | 932456. | 7868996. | 22033182. | 280.000 | 23.629 | 8439. | 6841 | 0.8094 | 0.8094 |
| 49 OSWEGO | 69145. | 683879. | 1997214. | 292.042 | 28.885 | 9891. | 2264 | 0.1973 | 0.1973 |
| 61 ALTGEN | 1423022. | 14230223. | 159630912. | 1121.774 | 112.177 | 10000. | 2371 | 0.2707 | 0.2707 |
| 62 ALTRSCO | 727368. | 7273680. | 10842671. | 149.067 | 14.907 | 10000. | 7033 | 0.7649 | 0.7460 |
| 63 PAWTKT | 331821. | 3318214. | 5873116. | 176.996 | 17.700 | 10000. | 5572 | 0.6484 | 0.6324 |
| 64 ENRON | 379410. | 3197335. | 8674734. | 271.311 | 22.864 | 8427. | 2299 | 0.5192 | 0.5192 |
| 65 Reading | -173098. | -1730976. | -4257291. | 0.000 | 0.000 | 0. | -8311 | -0.9500 | -0.9500 |
| 66 SELPB | -91542. | -915420. | -1489491. | 0.000 | 0.000 | 0. | -8311 | -0.9500 | -0.9500 |
| 67 SELPI | -23040. | -230400. | -563461. | 0.000 | 0.000 | 0. | -3828 | -0.4384 | -0.4384 |
| 68 LTB | -124830. | -1248300. | -1957834. | 0.000 | 0.000 | 0. | -8311 | -0.9500 | -0.9500 |
| SCH OUT | 230304. | 0. | 8981872. | 0.000 | 39.000 | 0. | | | |
| UNSC OUT | 27656. | 0. | 1133899. | 0.000 | 41.000 | 0. | | | |
| 0 INC SL | 0. | 0. | 0. | 0.000 | 0.000 | 0. | | | |
| OTHER | 0. | 0. | 0. | 0.000 | 0.000 | 0. | | | |
| HYDRO | 1866500. | 0. | 0. | 0.000 | 0.000 | 0. | | | |
| TOTAL*** | 23551594. | 208779856. | 490431712. | 234.904 | 20.824 | 8865. | | | |

| | MWH | DOLLARS | MILLS/KWH | MACH HRS |
|---|---|---|---|---|
| PUMPING | 362453. | 7397003. | 20.408 | 1609. |
| GENERATING | 264228. | 7397003. | 27.995 | 1173. |
| DISPATCH | 23453368. | | | |

PLIMF =0.0000

***** ONE UNIT SALES *****

BP-4 12059. 307057.

| | | |
|---|---|---|
| SH-3 | 32886. | 502797. |
| SH-4 | 11191. | 252713. |
| Man11CC | 3490. | 91729. |
| ME-YK | 5873. | 29624. |
| WYMN-4 | 5343. | 143097. |
| MILL#3 | 7558. | 42417. |
| OSP-1 | 34629. | 818052. |
| OSP-2 | 35274. | 833489. |

Exhibit ____ AG-PLC-8
Electricity Generation from Recent Resource Additions



| | MWh in 1995 |
|---|---|
| Manchester Street | 37,915 |
| Enron (Milford) | 379,410 |
| OSP 1 | 943,335 |
| OSP 2 | 932,456 |
| Altresco | 727,368 |
| Pawtucket | 331,821 |
| Total | 3,352,305 |

*Source: W-95 Workpapers of C.O. Paradise, page 60.1995 Month 13 Total MWh.*

# Exhibit ____ (AG-PLC-9)
# NEPCo Estimate of Energy Displaced by Manchester Street

**(3 pages, including this cover page)**

MEMORANDUM

**TO** J.HARRINGTON PLANNING & POWER **DATE** MAY 20, 1991

**FROM** L.D. FOWLER PLANNING & POWER **FILE**

**SUBJECT** **Displaced Energy with the Repowering of Manchester St.**

---

As requested I have summarized on the attached sheet a listing of units displaced by the energy produced by Manchester Street once repowered assuming a 1/1/95 in-service date. The displaced energy is stated relative to the case where the project is canceled and the existing units are retired. For the two years shown you will observe that Brayton Pt. 4 and Salem Harbor 4 account for over half of the displaced energy. Post 2000 a moderate amount of energy from peakers (and NUGs 2001+) are also displaced by Manchester Street.

Please let me know if additional information is needed.

(Attachment)

cc: JF Malley
JL Levett

L D Fowler

5/20/[illegible]

OD [illegible]

UNIT PRODUCTION DISPLACED WITH
REPOWERING MANCHESTER ST

| | 1995 | | 2000 | |
|---|---|---|---|---|
| | GWH | % | GWH | % |
| BP4 | 875 | 30% | 748 | 28% |
| SH4 | 672 | 23 | 876 | 33 |
| SH 1-3 | 419 | 14 | 7 | <1 |
| CANAL 1 | 189 | 6 | 140 | 5 |
| MT TOM | 88 | 3 | – | – |
| NU SLICE/NEP DIESELS/ WYMAN 4/NEPOOL/GTS | 259 | 8 | 768 | 29 |
| PURCH A-E's Cos/fuel | 458 | 16 | 144 | 5 |
| REPOWERING GWH: | 2960 | 100% | 2683 | 100% |

A-E's = Altresco, Pawtucket, ENRON, Newbay, Obrien, ware.

Exhibit ____ AG-PLC-10

Computation of Excess-Capitalized Energy Costs

### Fixed Charges of Excess Generation Capacity in 1996[1]

| | |
|---|---|
| OSP 1&2 | $ 79,811,000 |
| Altreseco | 40,001,000 |
| Pawtucket | 23,400,000 |
| Enron | 19,565,000 |
| Manchester Street | 106,499,664 |
| TOTAL | $ 269,276,664 |

### Fixed Charges of Equivalent Excess Peaking Capacity[2]

| | Unit Cost | MW | Total |
|---|---|---|---|
| OSP 1 | $88 | 115 | $10,119,840 |
| OSP 2 | $92 | 115 | $10,618,881 |
| Altreseco | $88 | 93 | $8,183,870 |
| Pawtucket | $92 | 63 | $5,817,300 |
| Enron | $102 | 83 | $8,465,386 |
| Manchester St. | $118 | 304 | $35,781,625 |
| TOTAL | | | $78,986,902 |

$22 M fuel saving

### Fuel Savings[3]

| | Total Generation (MWh) | Cost of Resource ($/MWh) | Cost of Alternative ($/MWh) | Fuel Savings ($/MWh) | Fuel Savings (Total $ in 1995) | Fuel Savings (Total $ in 1996) |
|---|---|---|---|---|---|---|
| Altreseco | 727,368 | 14.907 | 22.859 | 7.95 | 5,783,667 | 6,130,687 |
| Pawtucket | 331,821 | 17.700 | 22.859 | 5.16 | 1,711,699 | 1,814,401 |
| TOTAL | | | | | | $ 7,945,087 |

### Summary

| | |
|---|---|
| Fixed Charges | $ 269,276,664 |
| Capacity Costs | - $ 78,986,902 |
| Fuel Savings | - $ 7,945,087 |
| Excess Capitalized Energy Costs | $ 182,344,675 |

Notes:

[1] Manchester Street from Memo from BBG Teixeira to JJ Silva (June 7, 1993), page 5, net of non-fuel O&M from 1994 FERC form, escalated at 3%/yr to 1996. All others from Rating Agency Information Package 1995, page 44, supplied in response to AG-1-10.

[2] Calculated as in Exhibit ____AG-PLC-6. Difference in totals is due to omission of plants for which dispatch data was unavailable.

[3] All data are from Workpapers of CO Paradise, page 60 in W-95, which is attached to Exhibit AG-PLC-7. Cost of *alternative is average of Brayton Point 4 and Salem Harbor 4. Six percent inflation was applied to 1995 cost to* yield 1996 cost.

Exhibit____(AG-PLC-11)
NEES and MECo Energy Forecasts by Customer Class
*Table 1: NEES Energy Forecasts (GWh)*
*Page 1 of 2*



**Residential**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 6,320 | 6,276 | 6,232 | 6,188 | 6,145 | 6,102 | 6,150 | 6,199 | 6,248 | 6,298 | 6,348 |
| 1986 | | 6,330 | 6,694 | 6,848 | 6,896 | 7,045 | 7,025 | 7,057 | 7,023 | 7,005 | 6,977 |
| 1987 | | | 7,109 | 7,296 | 7,453 | 7,530 | 7,610 | 7,684 | 7,764 | 7,815 | 7,820 |
| 1988 | | | | 7,333 | 7,441 | 7,513 | 7,635 | 7,799 | 7,905 | 8,046 | 8,107 |
| 1989 | | | | | 7,833 | 8,087 | 8,256 | 8,462 | 8,575 | 8,745 | 8,859 |
| 1990 | | | | | | 8,098 | 8,179 | 8,307 | 8,403 | 8,506 | 8,667 |
| 1991 | | | | | | | 7,727 | 7,719 | 7,803 | 7,892 | 7,986 |
| 1992 | | | | | | | | 7,896 | 7,939 | 7,982 | 8,026 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 8,099 | 8,154 |

**Commercial**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 5,585 | 5,675 | 5,767 | 5,861 | 5,956 | 6,052 | 6,097 | 6,142 | 6,187 | 6,233 | 6,279 |
| 1986 | | 5,607 | 5,725 | 5,751 | 5,763 | 5,856 | 5,935 | 6,047 | 6,123 | 6,203 | 6,282 |
| 1987 | | | 6,411 | 6,704 | 6,989 | 7,189 | 7,384 | 7,568 | 7,753 | 7,968 | 8,122 |
| 1988 | | | | 6,843 | 7,111 | 7,172 | 7,363 | 7,596 | 7,831 | 8,072 | 8,283 |
| 1989 | | | | | 7,259 | 7,509 | 7,832 | 8,154 | 8,400 | 8,697 | 8,956 |
| 1990 | | | | | | 7,684 | 7,952 | 8,179 | 8,404 | 8,656 | 8,917 |
| 1991 | | | | | | | 7,502 | 7,470 | 7,610 | 7,747 | 7,892 |
| 1992 | | | | | | | | 7,397 | 7,557 | 7,720 | 7,887 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 7,756 | 7,941 |

Exhibit____(AG-PLC-11)

NEES and MECo Energy Forecasts by Customer Class

*Table 1: NEES Energy Forecasts (GWh)*

*Page 2 of 2*

**Industrial**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 4,686 | 4,779 | 4,873 | 4,969 | 5,067 | 5,167 | 5,277 | 5,390 | 5,505 | 5,622 | 5,717 |
| 1986 | | 4,592 | 4,806 | 4,961 | 4,959 | 5,050 | 5,115 | 5,238 | 5,331 | 5,440 | 5,562 |
| 1987 | | | 4,807 | 4,934 | 5,024 | 5,122 | 5,214 | 5,285 | 5,390 | 5,484 | 5,589 |
| 1988 | | | | 4,983 | 5,091 | 5,084 | 5,166 | 5,276 | 5,388 | 5,476 | 5,620 |
| 1989 | | | | | 5,259 | 5,326 | 5,499 | 5,596 | 5,700 | 5,827 | 5,963 |
| 1990 | | | | | | 5,254 | 5,335 | 5,465 | 5,611 | 5,743 | 5,900 |
| 1991 | | | | | | | 4,930 | 4,976 | 5,133 | 5,293 | 5,454 |
| 1992 | | | | | | | | 4,953 | 5,072 | 5,193 | 5,317 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 4,919 | 4,948 |

**System**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 16591 | 16730 | 16872 | 17018 | 17168 | 17321 | 17524 | 17731 | 17940 | 18153 | 18344 |
| 1986 | | 16529 | 17225 | 17560 | 17618 | 17951 | 18075 | 18342 | 18477 | 18648 | 18821 |
| 1987 | | | 18327 | 18934 | 19466 | 19841 | 20208 | 20537 | 20907 | 21267 | 21531 |
| 1988 | | | | 19159 | 19643 | 19769 | 20164 | 20671 | 21124 | 21594 | 22010 |
| 1989 | | | | | 20351 | 20922 | 21587 | 22212 | 22675 | 23269 | 23778 |
| 1990 | | | | | | 21036 | 21466 | 21951 | 22418 | 22905 | 23484 |
| 1991 | | | | | | | 20159 | 20165 | 20546 | 20932 | 21332 |
| 1992 | | | | | | | | 20246 | 20568 | 20895 | 21230 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 20774 | 21043 |

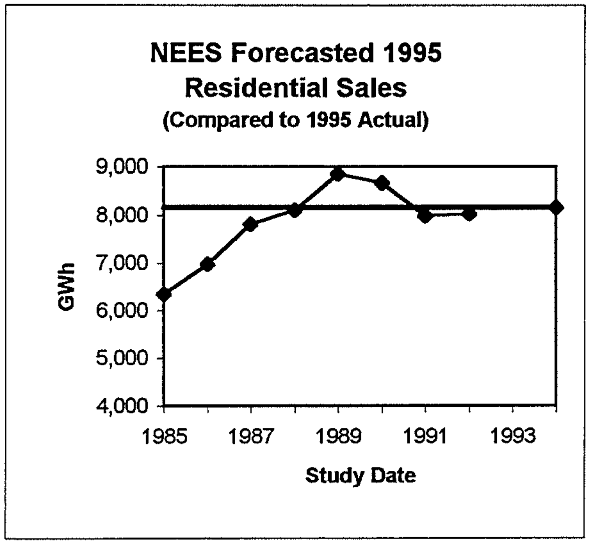
Notes: Total equals sum of residential, commercial and industrial sales.
Sales include C&LM.
Data for 1995 is projected from 1994.

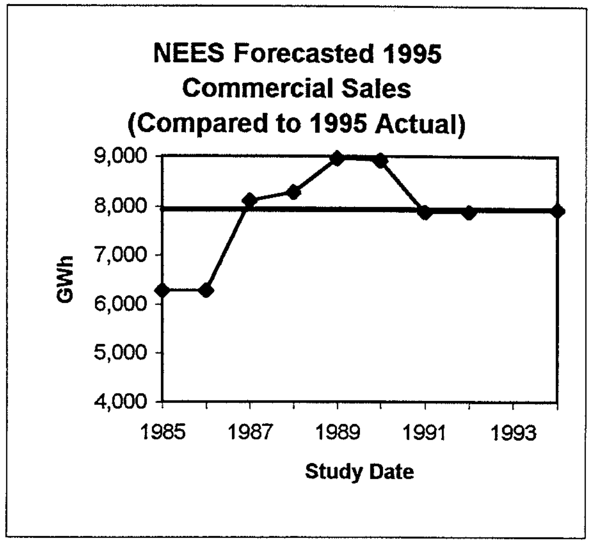
Sources: NEES Integrated Resource Plans, various years.

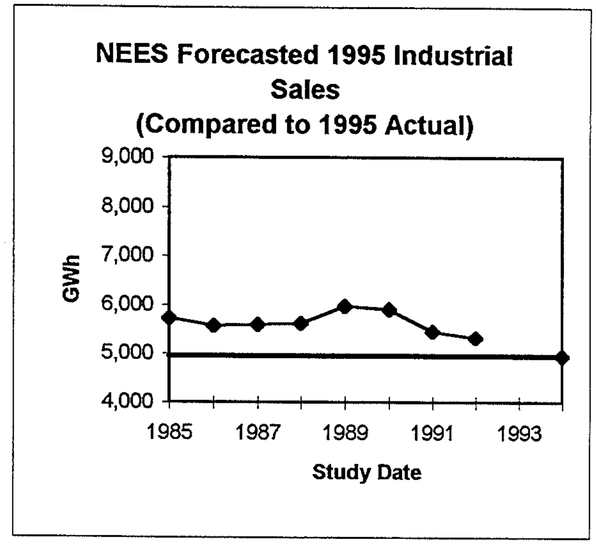
Exhibit____(AG-PLC-11)
NEES and MECo Energy Forecasts by Customer Class
*Figure 1: Comparison by Class of Actual 1994-95 NEES Sales with Forecasts of Various Vintages*

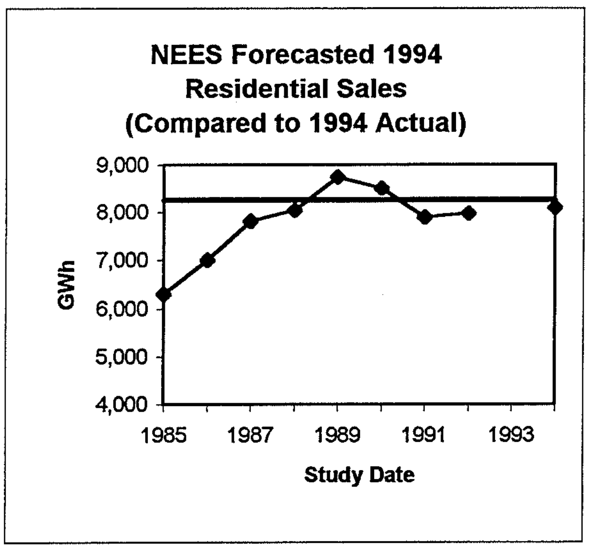


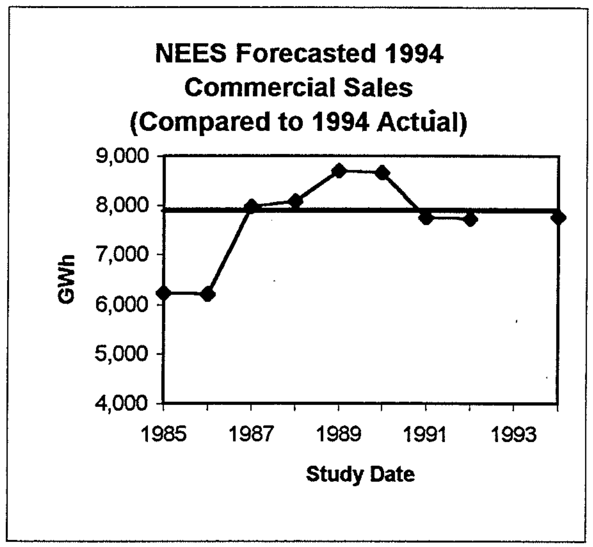
(Actuals shown as heavy line and forecasts shown as line with symbol.)

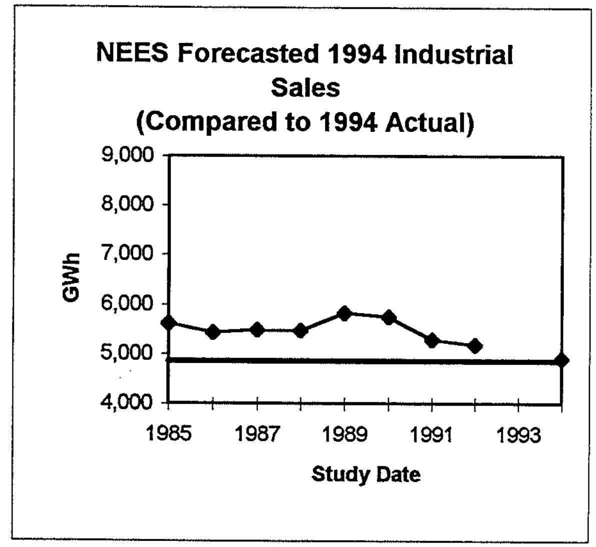


Exhibit____(AG-PLC-11)

NEES and MECo Energy Forecasts by Customer Class

*Table 2: MECo Energy Forecasts (GWh)*

*Page 1 of 2*

**Residential**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 4,641 | 4,574 | 4,508 | 4,443 | 4,379 | 4,316 | 4,358 | 4,400 | 4,443 | 4,486 | 4,529 |
| 1986 | | 4,612 | 4,916 | 5,010 | 5,043 | 5,151 | 5,116 | 5,149 | 5,128 | 5,121 | 5,088 |
| 1987 | | | 5,269 | 5,392 | 5,504 | 5,555 | 5,605 | 5,659 | 5,720 | 5,761 | 5,761 |
| 1988 | | | | 5,350 | 5,423 | 5,467 | 5,547 | 5,663 | 5,740 | 5,839 | 5,882 |
| 1989 | | | | | | | | | 6,419 | | |
| 1990 | | | | | | 6,024 | 6,082 | 6,177 | 6,239 | 6,304 | 6,412 |
| 1991 | | | | | | | 5,743 | 5,739 | 5,773 | 5,811 | 5,851 |
| 1992 | | | | | | | | 5,880 | 5,913 | 5,946 | 5,979 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 6,040 | 6,079 |

**Commercial**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 3,967 | 4,046 | 4,127 | 4,209 | 4,293 | 4,379 | 4,411 | 4,443 | 4,475 | 4,508 | 4,541 |
| 1986 | | 3,887 | 3,881 | 3,957 | 3,996 | 4,062 | 4,118 | 4,198 | 4,254 | 4,314 | 4,364 |
| 1987 | | | 4,601 | 4,841 | 5,069 | 5,240 | 5,399 | 5,555 | 5,705 | 5,863 | 5,991 |
| 1988 | | | | 4,921 | 5,145 | 5,193 | 5,350 | 5,542 | 5,775 | 5,925 | 6,088 |
| 1989 | | | | | | | | | 6,052 | | |
| 1990 | | | | | | 5,481 | 5,667 | 5,839 | 6,000 | 6,183 | 6,368 |
| 1991 | | | | | | | 5,380 | 5,351 | 5,425 | 5,494 | 5,565 |
| 1992 | | | | | | | | 5,209 | 5,337 | 5,469 | 5,604 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 5,446 | 5,559 |

Exhibit____(AG-PLC-11)

NEES and MECo Energy Forecasts by Customer Class

*Table 2: MECo Energy Forecasts (GWh)*

*Page 2 of 2*

**Industrial**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 3,761 | 3,827 | 3,894 | 3,963 | 4,032 | 4,103 | 4,195 | 4,288 | 4,384 | 4,482 | 4,582 |
| 1986 | | 3,711 | 3,887 | 3,986 | 4,000 | 4,075 | 4,145 | 4,253 | 4,338 | 4,448 | 4,552 |
| 1987 | | | 3,868 | 3,965 | 4,038 | 4,120 | 4,197 | 4,262 | 4,344 | 4,423 | 4,511 |
| 1988 | | | | 4,037 | 4,116 | 4,110 | 4,179 | 4,277 | 4,370 | 4,447 | 4,572 |
| 1989 | | | | | | | | | 4,660 | | |
| 1990 | | | | | | 4,310 | 4,385 | 4,498 | 4,620 | 4,734 | 4,872 |
| 1991 | | | | | | | 3,959 | 3,990 | 4,136 | 4,284 | 4,434 |
| 1992 | | | | | | | | 4,002 | 4,104 | 4,209 | 4,316 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 3,896 | 3,912 |

**System**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 12369 | 12447 | 12529 | 12615 | 12704 | 12798 | 12964 | 13131 | 13302 | 13476 | 13652 |
| 1986 | | 12210 | 12684 | 12953 | 13039 | 13288 | 13379 | 13600 | 13720 | 13883 | 14004 |
| 1987 | | | 13738 | 14198 | 14611 | 14915 | 15201 | 15476 | 15769 | 16047 | 16263 |
| 1988 | | | | 14308 | 14684 | 14770 | 15076 | 15482 | 15885 | 16211 | 16542 |
| 1989 | | | | | | | | | 17131 | | |
| 1990 | | | | | | 15815 | 16134 | 16514 | 16859 | 17221 | 17652 |
| 1991 | | | | | | | 15082 | 15080 | 15334 | 15589 | 15850 |
| 1992 | | | | | | | | 15091 | 15354 | 15624 | 15899 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 15382 | 15550 |

Notes: Total equals sum of residential, commercial and industrial sales.
Sales include C&LM.
Data for 1995 is projected from 1994.

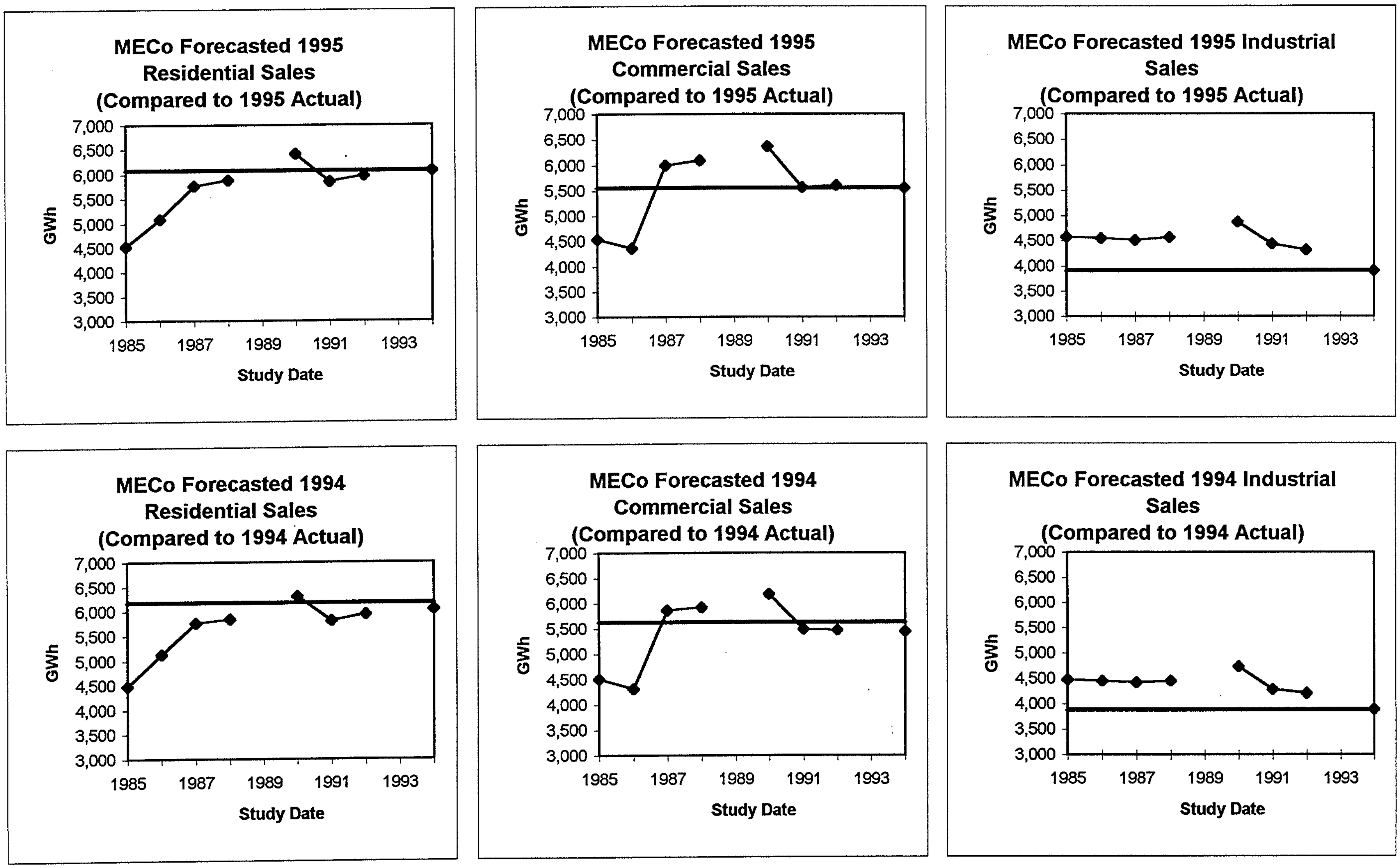
Sources: NEES Integrated Resource Plans, various years.

Exhibit____(AG-PLC-11)

NEES and MECo Energy Forecasts by Customer Class

*Figure 2: Comparison by Class of Actual 1994-1995 MECo Sales with Forecasts of Various Vintages*

(Actuals shown as heavy line and forecasts shown as line with symbol.)



Exhibit____(AG-PLC-12)

NEES and MECo Energy Forecast Errors by Customer Class

*Table 1: NEES Energy Forecast Errors*

*Page 1 of 2*

*(Actual-Forecast)*

**Residential**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 140 | 537 | 1,036 | 1,578 | 1,807 | 1,824 | 1,756 | 1,824 | 1,875 | 1,955 | 1,806 |
| 1986 | | 483 | 574 | 918 | 1,056 | 881 | 881 | 966 | 1,100 | 1,248 | 1,177 |
| 1987 | | | 159 | 470 | 499 | 396 | 296 | 339 | 359 | 438 | 334 |
| 1988 | | | | 433 | 511 | 413 | 271 | 224 | 218 | 207 | 47 |
| 1989 | | | | | 119 | -161 | -350 | -439 | -452 | -492 | -705 |
| 1990 | | | | | | -172 | -273 | -284 | -280 | -253 | -513 |
| 1991 | | | | | | | 179 | 304 | 320 | 361 | 168 |
| 1992 | | | | | | | | 127 | 184 | 271 | 128 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 154 | |

**Commercial**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 220 | 520 | 905 | 1,235 | 1,463 | 1,493 | 1,339 | 1,981 | 1,504 | 1,661 | 1,662 |
| 1986 | | 588 | 947 | 1,345 | 1,656 | 1,689 | 1,501 | 2,076 | 1,568 | 1,691 | 1,659 |
| 1987 | | | 261 | 392 | 430 | 356 | 52 | 555 | -62 | -74 | -181 |
| 1988 | | | | 253 | 308 | 373 | 73 | 527 | -140 | -178 | -342 |
| 1989 | | | | | 160 | 36 | -396 | -31 | -709 | -803 | -1,015 |
| 1990 | | | | | | -139 | -516 | -56 | -713 | -762 | -976 |
| 1991 | | | | | | | -66 | 653 | 81 | 147 | 49 |
| 1992 | | | | | | | | 726 | 134 | 174 | 54 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 138 | |

Exhibit____(AG-PLC-12)

NEES and MECo Energy Forecast Errors by Customer Class

*Table 1: NEES Energy Forecast Errors*

*Page 2 of 2*

*(Actual-Forecast)*

**Industrial**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | -63 | -18 | -8 | 95 | 42 | -93 | -327 | 2,863 | -645 | -763 | -769 | |
| 1986 | | 169 | 59 | 103 | 150 | 24 | -165 | 3,015 | -471 | -581 | -614 | |
| 1987 | | | 58 | 130 | 85 | -48 | -264 | 2,968 | -530 | -625 | -641 | |
| 1988 | | | | 81 | 18 | -10 | -216 | 2,977 | -528 | -617 | -672 | 731 |
| 1989 | | | | | -150 | -252 | -549 | 2,657 | -840 | -968 | -1,015 | |
| 1990 | | | | | | -180 | -385 | 2,788 | -751 | -884 | -952 | |
| 1991 | | | | | | | 20 | 3,277 | -273 | -434 | -506 | |
| 1992 | | | | | | | | 3,300 | -212 | -334 | -369 | |
| 1993 | | | | | | | | | | | | |
| 1994 | | | | | | | | | | -60 | | |

**System**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 297 | 1,039 | 1,933 | 2,908 | 3,312 | 3,224 | -12,650 | 2,662 | 2,734 | 2,853 | 2,699 |
| 1986 | | 1,240 | 1,580 | 2,366 | 2,862 | 2,594 | -13,201 | 2,051 | 2,197 | 2,358 | 2,222 |
| 1987 | | | 478 | 992 | 1,014 | 704 | -15,334 | -144 | -233 | -261 | -488 |
| 1988 | | | | 767 | 837 | 776 | -15,290 | -278 | -450 | -588 | -967 |
| 1989 | | | | | 129 | -377 | -16,713 | -1,819 | -2,001 | -2,263 | -2,735 |
| 1990 | | | | | | -491 | -16,592 | -1,558 | -1,744 | -1,899 | -2,441 |
| 1991 | | | | | | | -15,285 | 228 | 128 | 74 | -289 |
| 1992 | | | | | | | | 147 | 106 | 111 | -187 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 232 | |

Exhibit____(AG-PLC-12)
NEES and MECo Energy Forecast Errors by Customer Class
*Table 2: Percent Difference Between NEES's Actual Post-DSM Sales and Forecasts*
*(Actual-Forecast)/Forecast*



**Residential**

| Study Date | 1994 | 1995 |
|---|---|---|
| 1985 | 31% | 28% |
| 1986 | 18% | 17% |
| 1987 | 6% | 4% |
| 1988 | 3% | 1% |
| 1989 | -6% | -8% |
| 1990 | -3% | -6% |
| 1991 | 5% | 2% |
| 1992 | 3% | 2% |
| 1993 | | |
| 1994 | 2% | |

**Industrial**

| Study Date | 1994 | 1995 |
|---|---|---|
| 1985 | -14% | -13% |
| 1986 | -11% | -11% |
| 1987 | -11% | -11% |
| 1988 | -11% | -12% |
| 1989 | -17% | -17% |
| 1990 | -15% | -16% |
| 1991 | -8% | -9% |
| 1992 | -6% | -7% |
| 1993 | | |
| 1994 | -1% | |

**Commercial**

| Study Date | 1994 | 1995 |
|---|---|---|
| 1985 | 27% | 26% |
| 1986 | 27% | 26% |
| 1987 | -1% | -2% |
| 1988 | -2% | -4% |
| 1989 | -9% | -11% |
| 1990 | -9% | -11% |
| 1991 | 2% | 1% |
| 1992 | 2% | 1% |
| 1993 | | |
| 1994 | 2% | |

**System**

| Study Date | 1994 | 1995 |
|---|---|---|
| 1985 | 16% | 15% |
| 1986 | 13% | 12% |
| 1987 | -1% | -2% |
| 1988 | -3% | -4% |
| 1989 | -10% | -12% |
| 1990 | -8% | -10% |
| 1991 | 0% | -1% |
| 1992 | 1% | -1% |
| 1993 | | |
| 1994 | 1% | |

Exhibit____(AG-PLC-12)

NEES and MECo Energy Forecast Errors by Customer Class

*Table 3: MECo Energy Forecast Errors*

*Page 1 of 2*

*(Actual-Forecast)*

**Residential**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 142 | 476 | 889 | 1,340 | 1,543 | 1,576 | 1,530 | 1,600 | 1,623 | 1,685 | 1,550 |
| 1986 | | 438 | 481 | 773 | 879 | 741 | 772 | 851 | 938 | 1,050 | 991 |
| 1987 | | | 128 | 391 | 418 | 337 | 283 | 341 | 346 | 410 | 318 |
| 1988 | | | | 433 | 499 | 425 | 341 | 337 | 326 | 332 | 197 |
| 1989 | | | | | | | | | -353 | | |
| 1990 | | | | | | -132 | -194 | -177 | -173 | -133 | -333 |
| 1991 | | | | | | | 145 | 261 | 293 | 360 | 228 |
| 1992 | | | | | | | | 120 | 153 | 225 | 100 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 131 | 0 |

**Commercial**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 163 | 384 | 659 | 870 | 1,036 | 1,008 | 855 | 848 | 957 | 1,120 | 1,018 |
| 1986 | | 543 | 905 | 1,122 | 1,333 | 1,325 | 1,148 | 1,093 | 1,178 | 1,314 | 1,195 |
| 1987 | | | 185 | 238 | 260 | 147 | -133 | -264 | -273 | -235 | -432 |
| 1988 | | | | 158 | 184 | 194 | -84 | -251 | -343 | -297 | -529 |
| 1989 | | | | | | | | | -620 | | |
| 1990 | | | | | | -94 | -401 | -548 | -568 | -555 | -809 |
| 1991 | | | | | | | -114 | -60 | 7 | 134 | -6 |
| 1992 | | | | | | | | 82 | 95 | 159 | -45 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 182 | 0 |

Exhibit____(AG-PLC-12)

NEES and MECo Energy Forecast Errors by Customer Class

*Table 3: MECo Energy Forecast Errors*

*Page 2 of 2*

*(Actual-Forecast)*

**Industrial**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | -27 | 30 | 52 | 176 | 137 | 11 | -220 | -378 | -537 | -597 | -670 |
| 1986 | | 146 | 59 | 153 | 169 | 39 | -170 | -343 | -491 | -563 | -640 |
| 1987 | | | 78 | 174 | 131 | -6 | -222 | -352 | -497 | -538 | -599 |
| 1988 | | | | 102 | 53 | 4 | -204 | -367 | -523 | -562 | -660 |
| 1989 | | | | | | | | | -813 | | |
| 1990 | | | | | | -196 | -410 | -588 | -773 | -849 | -960 |
| 1991 | | | | | | | 16 | -80 | -289 | -399 | -522 |
| 1992 | | | | | | | | -92 | -257 | -324 | -404 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | -11 | 0 |

**System**

| Study Date | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1985 | 278 | 890 | 1,600 | 2,386 | 2,716 | 2,595 | 2,165 | 2,070 | 2,043 | 2,208 | 1,898 |
| 1986 | | 1,127 | 1,445 | 2,048 | 2,381 | 2,105 | 1,750 | 1,601 | 1,625 | 1,801 | 1,546 |
| 1987 | | | 391 | 803 | 809 | 478 | -72 | -275 | -424 | -363 | -713 |
| 1988 | | | | 693 | 736 | 623 | 53 | -281 | -540 | -527 | -992 |
| 1989 | | | | | | | | | -1,786 | | |
| 1990 | | | | | | -422 | -1,005 | -1,313 | -1,514 | -1,537 | -2,102 |
| 1991 | | | | | | | 47 | 121 | 11 | 95 | -300 |
| 1992 | | | | | | | | 110 | -9 | 60 | -349 |
| 1993 | | | | | | | | | | | |
| 1994 | | | | | | | | | | 302 | 0 |

Exhibit____(AG-PLC-12)

NEES and MECo Energy Forecast Errors by Customer Class

*Table 4: Percent Difference Between MECo's Actual Post-DSM Sales and Forecasts (Actual-Forecast)/Forecast*

**Residential**

| Study Date | 1994 | 1995 |
|---|---|---|
| 1985 | 38% | 34% |
| 1986 | 21% | 19% |
| 1987 | 7% | 6% |
| 1988 | 6% | 3% |
| 1989 | | |
| 1990 | -2% | -5% |
| 1991 | 6% | 4% |
| 1992 | 4% | 2% |
| 1993 | | |
| 1994 | 2% | |

**Industrial**

| Study Date | 1994 | 1995 |
|---|---|---|
| 1985 | -13% | -15% |
| 1986 | -13% | -14% |
| 1987 | -12% | -13% |
| 1988 | -13% | -14% |
| 1989 | | |
| 1990 | -18% | -20% |
| 1991 | -9% | -12% |
| 1992 | -8% | -9% |
| 1993 | | |
| 1994 | 0% | |

**Commercial**

| Study Date | 1994 | 1995 |
|---|---|---|
| 1985 | 25% | 22% |
| 1986 | 30% | 27% |
| 1987 | -4% | -7% |
| 1988 | -5% | -9% |
| 1989 | | |
| 1990 | -9% | -13% |
| 1991 | 2% | 0% |
| 1992 | 3% | -1% |
| 1993 | | |
| 1994 | 3% | 0% |

**System**

| Study Date | 1994 | 1995 |
|---|---|---|
| 1985 | 16% | 14% |
| 1986 | 13% | 11% |
| 1987 | -2% | -4% |
| 1988 | -3% | -6% |
| 1989 | | |
| 1990 | -9% | -12% |
| 1991 | 1% | -2% |
| 1992 | 0% | -2% |
| 1993 | | |
| 1994 | 2% | |

Exhibit____(AG-PLC-13)

Averages of NEES and MECo Energy Forecast Errors Over Relevant Periods

*Table 1: NEES Average Error*
*(Actual-Forecast)/Forecast*

| **Residential** | 1994 | 1995 | Avg. 1994-95 |
|---|---|---|---|
| Average Error | | | |
| 1987-89 | 1% | -1% | 0% |
| 1987-90 | 0% | -2% | -1% |
| 1987-91 | 1% | -1% | 0% |
| 1989-90 | -4% | -7% | -6% |
| 1989-91 | -1% | -4% | -3% |
| Ratio to System Error | | | |
| 1987-89 | -0.19 | 0.17 | 0.02 |
| 1987-90 | 0.02 | 0.32 | 0.19 |
| 1987-91 | -0.19 | 0.23 | 0.05 |
| 1989-90 | 0.48 | 0.63 | 0.56 |
| 1989-91 | 0.23 | 0.51 | 0.39 |

| **Industrial** | 1994 | 1995 | Avg. 1994-95 |
|---|---|---|---|
| Average Error | | | |
| 1987-89 | -13% | -13% | -13% |
| 1987-90 | -14% | -14% | -14% |
| 1987-91 | -13% | -13% | -13% |
| 1989-90 | -16% | -17% | -16% |
| 1989-91 | -13% | -14% | -14% |
| Ratio to System Error | | | |
| 1987-89 | 2.87 | 2.23 | 2.50 |
| 1987-90 | 2.49 | 1.98 | 2.20 |
| 1987-91 | 2.91 | 2.20 | 2.50 |
| 1989-90 | 1.78 | 1.51 | 1.63 |
| 1989-91 | 2.28 | 1.83 | 2.02 |

| **Commercial** | 1994 | 1995 | Avg. 1994-95 |
|---|---|---|---|
| Average Error | | | |
| 1987-89 | -4% | -6% | -5% |
| 1987-90 | -5% | -7% | -6% |
| 1987-91 | -4% | -6% | -5% |
| 1989-90 | -9% | -11% | -10% |
| 1989-91 | -5% | -7% | -6% |
| Ratio to System Error | | | |
| 1987-89 | 0.90 | 0.97 | 0.94 |
| 1987-90 | 0.96 | 1.00 | 0.99 |
| 1987-91 | 0.89 | 0.94 | 0.92 |
| 1989-90 | 1.00 | 1.02 | 1.01 |
| 1989-91 | 0.91 | 0.93 | 0.92 |

| **System** | 1994 | 1995 | Avg. 1994-95 |
|---|---|---|---|
| Average Error | | | |
| 1987-89 | -5% | -6% | -5% |
| 1987-90 | -5% | -7% | -6% |
| 1987-91 | -4% | -6% | -5% |
| 1989-90 | -9% | -11% | -10% |
| 1989-91 | -6% | -8% | -7% |

Exhibit____(AG-PLC-13)



# Averages of NEES and MECo Energy Forecast Errors Over Relevant Periods

*Table 2: MECo Average Error*
*(Actual-Forecast)/Forecast*

| **Residential** | 1994 | 1995 | Avg. 1994-95 |
|---|---|---|---|
| Average Error | | | |
| 1987-89 | 6% | 4% | 5% |
| 1987-90 | 4% | 1% | 2% |
| 1987-91 | 4% | 2% | 3% |
| 1989-90 | -2% | -5% | -4% |
| 1989-91 | 2% | -1% | 1% |
| Ratio to System Error | | | |
| 1987-89 | -2.32 | -0.85 | -1.36 |
| 1987-90 | -0.74 | -0.16 | -0.39 |
| 1987-91 | -1.22 | -0.31 | -0.64 |
| 1989-90 | 0.24 | 0.44 | 0.35 |
| 1989-91 | -0.49 | 0.09 | -0.13 |

| **Industrial** | 1994 | 1995 | Avg. 1994-95 |
|---|---|---|---|
| Average Error | | | |
| 1987-89 | -12% | -14% | -13% |
| 1987-90 | -14% | -16% | -15% |
| 1987-91 | -13% | -15% | -14% |
| 1989-90 | -18% | -20% | -19% |
| 1989-91 | -14% | -16% | -15% |
| Ratio to System Error | | | |
| 1987-89 | 4.50 | 2.67 | 3.30 |
| 1987-90 | 2.96 | 2.13 | 2.45 |
| 1987-91 | 3.76 | 2.45 | 2.93 |
| 1989-90 | 2.01 | 1.65 | 1.81 |
| 1989-91 | 3.28 | 2.28 | 2.66 |

| **Commercial** | Average Error 1994 | 1995 | Avg. 1994-95 |
|---|---|---|---|
| Average Error | | | |
| 1987-89 | -5% | -8% | -6% |
| 1987-90 | -6% | -10% | -8% |
| 1987-91 | -4% | -7% | -6% |
| 1989-90 | -9% | -13% | -11% |
| 1989-91 | -3% | -6% | -5% |
| Ratio to System Error | | | |
| 1987-89 | 1.64 | 1.53 | 1.57 |
| 1987-90 | 1.25 | 1.28 | 1.27 |
| 1987-91 | 1.13 | 1.19 | 1.16 |
| 1989-90 | 1.01 | 1.07 | 1.04 |
| 1989-91 | 0.79 | 0.93 | 0.87 |

| **System** | Average Error 1994 | 1995 | Avg. 1994-95 |
|---|---|---|---|
| Average Error | | | |
| 1987-89 | -3% | -5% | -4% |
| 1987-90 | -5% | -7% | -6% |
| 1987-91 | -3% | -6% | -5% |
| 1989-90 | -9% | -12% | -10% |
| 1989-91 | -4% | -7% | -6% |

Exhibit ____(AG-PLC-14)
Excess Capitalized Energy Allocator

| | | R-1/R-2 | R-4 | St. Lighting | G-1 | G-2 | G3/G4 | TOTAL |
|---|---|---|---|---|---|---|---|---|
| [1] | % of energy with losses | 37.62% | 0.28% | 0.61% | 8.50% | 13.69% | 39.29% | 100.00% |
| [2] | ratio of forecasting error to system error | 0.00 | 0.00 | 0.00 | 1.04 | 1.04 | 2.08 | |
| [3] | share of error energy forecast | 0.00000 | 0.00000 | 0.00000 | 0.08845 | 0.14241 | 0.81538 | 1.04625 |
| [4] | Normalized | 0.00000 | 0.00000 | 0.00000 | 0.08454 | 0.13612 | 0.77934 | 1.00000 |

Notes:
[1]: From exhibit AG-PLC-27
[2]: Calculated from Exhibit AG-PLC-13. Average of NEES and MECo error ratio results for the 1987-91 period. Negative errors were set to zero. G-3/G-4 calculated as 62% (industrial) × 2.71 + 38% (commercial) × 1.04. 62% is the ratio of industrial sales to G-3/G-4 sales, from the 1994 FERC form.
[3]: [1] × [2]
[4]: [3] ÷ [Total]

Exhibit ____(AG-PLC-15)
Excess Capacity Allocator

| | | R-1/R-2 | R-4 | St. Light | G-1 | G-2 | G3/G4 | TOTAL |
|---|---|---|---|---|---|---|---|---|
| [1] | % of coincident peak with losses | 34.66% | 0.17% | 0.00% | 12.04% | 16.82% | 36.31% | 100.00% |
| [2] | Ratio of forecasting error to system error | 0 | 0 | 0.00% | 1.0400 | 1.0400 | 2.0754 | |
| [3] | Share of error energy forecast | 0.00000 | 0.00000 | 0.00000 | 0.12519 | 0.17493 | 0.75355 | 1.05368 |
| [4] | Normalized | 0.00000 | 0.00000 | 0.00000 | 0.11882 | 0.16602 | 0.71516 | 1.00000 |

Notes:

[1]: From exhibit AG-PLC-27

[2]: Calculated from Exhibit AG-PLC-13. Average of NEES and MECo error ratio results for the 1987-91 period. Negative errors were set to zero. G-3/G-4 calculated as 62% (industrial) × 2.71 + 38% (commercial) × 1.04. 62% is the ratio of industrial sales to G-3/G-4 sales, from the 1994 FERC form.

[3]: [1] × [2]

[4]: [3] ÷ [Total]

Exhibit ____ (AG-PLC-16)
Reallocation of Excess Generation Costs ($million)

| | | R-1 / R-2 | R-4 | (R-1, R-2, R-4) | G-1 | G-2 | (G-1,G-2) | G-3/G4 | Light |
|---|---|---|---|---|---|---|---|---|---|
| ***Excess Capitalized Energy*** | | | | | | | | | |
| **NEPCO COST** | **MECO SHARE** | | | | | | | | |
| | 72.80% | | | | | | | | |
| $182.30 | $132.71 | | | | | | | | |
| A) | WHAM-D Allocator | 34.88% | 0.25% | 35.13% | 10.17% | 14.80% | 24.97% | 39.57% | 0.33% |
| | Allocated Costs | $46.29 | $0.33 | $46.62 | $13.50 | $19.64 | $33.14 | $52.52 | $0.44 |
| B) | Excess Capitalized Energy Allocator | 0.00% | 0.00% | 0.00% | 8.45% | 13.61% | 22.07% | 77.93% | 0.00% |
| | Allocated Costs | $0.00 | $0.00 | $0.00 | $11.22 | $18.06 | $29.28 | $103.43 | $0.00 |
| C) | Difference (B- A) | ($46.29) | ($0.33) | ($46.62) | ($2.28) | ($1.58) | ($3.85) | $50.91 | ($0.44) |
| ***Excess Capacity*** | | | | | | | | | |
| **NEPCO COST** | **MECO SHARE** | | | | | | | | |
| | 72.80% | | | | | | | | |
| $86.40 | $62.90 | | | | | | | | |
| D) | MECO WHAM-D Allocator | 34.88% | 0.25% | 35.13% | 10.17% | 14.80% | 24.97% | 39.57% | 0.33% |
| | Allocated Costs | $21.94 | $0.16 | $22.10 | $6.40 | $9.31 | $15.71 | $24.89 | $0.21 |
| E) | Excess Capacity Allocator | 0.00% | 0.00% | 0.00% | 11.88% | 16.60% | 28.48% | 71.52% | 0.00% |
| | Allocated Costs | $0.00 | $0.00 | $0.00 | $7.47 | $10.44 | $17.92 | $44.98 | $0.00 |
| F) | Difference (E-D) | ($21.94) | ($0.16) | ($22.10) | $1.08 | $1.13 | $2.21 | $20.09 | ($0.21) |
| ***Total Difference (C + F)*** | | ($68.23) | ($0.49) | ($68.72) | ($1.20) | ($0.44) | ($1.64) | $71.01 | ($0.65) |

Exhibit____(AG-PLC-17)

NEES's Average Percentage Forecasting Errors, 1991-94

(Actual-Forecast)/Forecast

**Residential**

| Study Date | 1991 | 1992 | 1993 | 1994 | | |
|---|---|---|---|---|---|---|
| 1985 | 29% | | | | | |
| 1986 | 13% | 14% | 16% | | | |
| 1987 | 4% | 4% | 5% | | | |
| 1988 | 4% | 3% | 3% | 3% | | |
| 1989 | | -5% | -5% | -6% | | |
| 1990 | | | -3% | -3% | | |
| 1991 | | | | 5% | | |
| Average | 12.1% | 3.9% | 2.9% | -0.4% | Overall Average | 4.8% |
| Absolute Average | 12.1% | 3.9% | 2.9% | 0.4% | Ratio of Res. to Ind. | 23% |

**Commercial**

| Study Date | 1991 | 1992 | 1993 | 1994 | | |
|---|---|---|---|---|---|---|
| 1985 | 22% | | | | | |
| 1986 | 25% | 34% | | | | |
| 1987 | 1% | 7% | -1% | | | |
| 1988 | 1% | 7% | -2% | -2% | | |
| 1989 | | 0% | -8% | -9% | | |
| 1990 | | | -8% | -9% | | |
| 1991 | | | | 2% | | |
| Average | 12.2% | 12.1% | -4.9% | -6.7% | | |
| Absolute Average | 12.2% | 12.1% | 4.9% | 6.7% | Overall Average | 9.0% |

**Industrial**

| Study Date | 1991 | 1992 | 1993 | 1994 | | |
|---|---|---|---|---|---|---|
| 1985 | -6% | | | | | |
| 1986 | -3% | 58% | | | | |
| 1987 | -5% | 56% | -10% | | | |
| 1988 | -4% | 56% | -10% | -11% | | |
| 1989 | | 47% | -15% | -17% | | |
| 1990 | | | -13% | -15% | | |
| 1991 | | | | -8% | | |
| Average | -4.7% | 54.4% | -11.9% | -14.4% | | |
| Absolute Average | 4.7% | 54.4% | 11.9% | 14.4% | Overall Average | 21.4% |

Exhibit____(AG-PLC-17)
NEES's Average Percentage Forecasting Errors, 1991-94

(Forecast-Actual)/Actual

**Residential**

| Study Date | 1991 | 1992 | 1993 | 1994 | | |
|---|---|---|---|---|---|---|
| 1985 | -22% | | | | | |
| 1986 | -11% | -12% | | | | |
| 1987 | -4% | -4% | -4% | | | |
| 1988 | -3% | -3% | -3% | -3% | | |
| 1989 | | 5% | 6% | 6% | | |
| 1990 | | | 3% | 3% | | |
| 1991 | | | | -4% | | |
| Average | -10.1% | -3.4% | 0.5% | 0.5% | Overall Average | 3.6% |
| Absolute Average | 10.1% | 3.4% | 0.5% | 0.5% | Ratio of Res. to Ind. | 33.7% |

**Commercial**

| Study Date | 1991 | 1992 | 1993 | 1994 | | |
|---|---|---|---|---|---|---|
| 1985 | -18% | | | | | |
| 1986 | -20% | -19% | | | | |
| 1987 | -1% | 1% | 1% | | | |
| 1988 | -1% | 1% | 2% | 2% | | |
| 1989 | | 9% | 9% | 10% | | |
| 1990 | | | 9% | 10% | | |
| 1991 | | | | -2% | | |
| Average | -10.0% | -2.1% | 5.3% | 5.1% | | |
| Absolute Average | 10.0% | 2.1% | 5.3% | 5.1% | Overall Average | 5.6% |

**Industrial**

| Study Date | 1991 | 1992 | 1993 | 1994 | | |
|---|---|---|---|---|---|---|
| 1985 | 7% | | | | | |
| 1986 | 3% | 7% | | | | |
| 1987 | 5% | 8% | 11% | | | |
| 1988 | 4% | 8% | 11% | 13% | | |
| 1989 | | 15% | 17% | 20% | | |
| 1990 | | | 15% | 18% | | |
| 1991 | | | | 9% | | |
| Average | 4.9% | 9.7% | 13.6% | 14.9% | | |
| Absolute Average | 4.9% | 9.7% | 13.6% | 14.9% | Overall Average | 10.8% |

Exhibit ____ (AG-PLC-18)
Summary of MECO Distribution Allocators



| | Residential | | | Small General Service | | | | Street |
|---|---|---|---|---|---|---|---|---|
| **Allocator** | **R-1 / R-2** | **R-4** | **Total** | **G-1** | **G-2** | **Total** | **G-3/G-4** | **Light** |
| WHAM for Demand | 34.88% | 0.25% | 35.13% | 10.17% | 14.80% | 24.97% | 39.57% | 0.33% |
| WHAM for Energy | 36.89% | 0.27% | 37.16% | 8.82% | 13.89% | 22.71% | 39.52% | 0.60% |
| Sum of Customer Max. Demand @ Primary | 60.81% | 0.26% | 61.07% | 8.73% | 8.94% | 17.67% | 20.75% | 0.53% |
| Sum of Customer Max. Demand @ Step-Down | 67.38% | 0.28% | 67.66% | 9.67% | 9.68% | 19.35% | 12.41% | 0.58% |
| Sum of Customer Max. Demand @ Secondary | 76.95% | 0.32% | 77.27% | 11.05% | 11.02% | 22.07% | 0.00% | 0.67% |
| Number of Customers | 89.44% | 0.08% | 89.52% | 8.99% | 1.18% | 10.17% | 0.23% | 0.10% |
| Number of Customer Exclude Street Light | 89.53% | 0.08% | 89.61% | 8.99% | 1.18% | 10.17% | 0.23% | 0.00% |
| Service Drop | 87.94% | 0.09% | 88.03% | 8.40% | 3.10% | 11.50% | 0.48% | 0.00% |

*Source: Mass Electric, Exhibit PTZ-1, page 17 of 18.*

**Exhibit ____ (AG-PLC-19)**
**Excerpts Concerning Dependence of**
**Transformer Capacity on Energy Loads**

**(6 pages, including this cover page)**

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# Standard Handbook for Electrical Engineers


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be limited by reasonable consideration of the effect on insulation life and the probable effect on transformer life.

**142. The insulation life of a transformer** is defined as the time required for the mechanical strength of the insulation material to lose a specified fraction of its initial value. Loss of 90% of the tensile strength is the usual basis for evaluating paper.

**143. The aging of insulation** is a chemical process which occurs more rapidly at higher temperatures according to the Arrhenius reaction-rate theory, as expressed in Eq. (10-63);

$$h = \epsilon^{[K_1+K_2/(C+273)]} \tag{10-63}$$

where $C$ = °C temperature of insulation, $K_1$, $K_2$ = constants determined by test, and $h$ = hours of life.

Use of this equation permits results of relatively short-duration tests at relatively high temperatures to be extrapolated to indicate probable insulation life at moderate temperatures. ANSI C57.92-1962 contains loading recommendations for power transformers with 55°C average winding-rise insulation systems based upon extrapolated life tests. *NEMA Publ.* TR 98-1964 contains corresponding recommendations for power transformers, with 65°C average winding-rise insulation systems. Figure 10-37 shows the corresponding curves of rate of loss of life as a function of temperature.

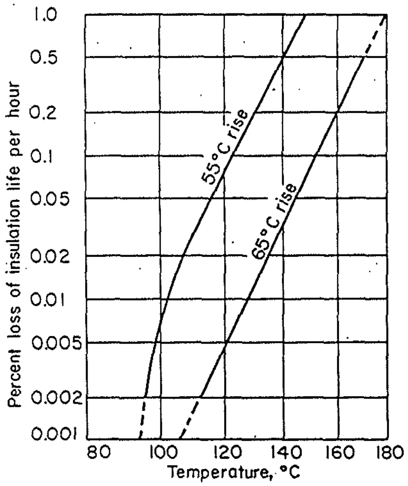


**Fig. 10-37.** Loss of insulation life as affected by temperature. (The 55°C curve from ANSI C-57.92-1962; the 65°C curve from *NEMA Publ.* TR 98-1964.)

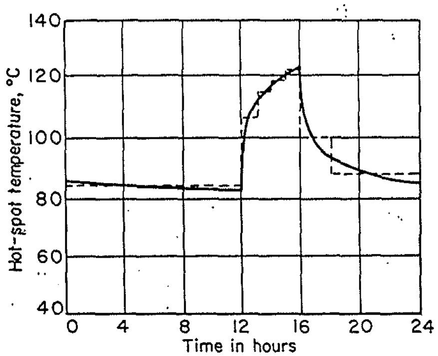


**Fig. 10-38.** Equivalent stepped curve of hot-spot temperature for loss-of-life calculation of a daily load cycle.

More information about this general concept has been worked out for distribution transformers.[1]

**144.** To determine the aging of the insulation resulting from a specific daily load cycle, (1) establish an approximately equivalent stepped load cycle, (2) calculate the resulting curve of hot-spot temperature by the methods of Par. 68, (3) replace the hot-spot temperature curve by an approximately equivalent stepped curve, (4) calculate the percent aging for each step from the applicable curve of Fig. 10-37, and (5) add the aging for all the steps in the daily cycle. The result is the fraction of insulation life used up each day. The reciprocal is the number of days of total insulation life if the same load cycle repeats every day.

**145. Example.** Consider the transformer used in the example of Par. 71, with a daily load cycle of 4 h at 140% load and 20 h at 80% load in a 30°C ambient. The hot-spot temperature curve shown in Fig. 10-23 is reproduced in Fig. 10-38, together with an equivalent stepped curve. The calculation of loss of life per day is shown in Table 10-8, with steps below 95°C neglected.

[1]ANSI C57.100-1974, Test Procedure for Thermal Evaluation of Oil-immersed Distribution Trans-



A loss of 0.232% of the insulation life each day gives an insulation life of 431 days, or 1.2 years. For comparison, a transformer with a 55°C average winding-rise insulation system (65°C hot-spot rise) operating in a 30°C ambient would have a hot-spot temperature of 95°C and would use 0.0010% of the insulation life each hour. This gives an insulation life of 11.4 years. The shortening of the insulation life from 11.4 to 1.2 years is a measure of the severity of the load cycle. The actual transformer life may, of course, be shorter or longer, depending on exposure to overvoltage, overcurrent, shock, contamination, etc.

**TABLE 10-8. Calculation of Loss of Life per Day on Daily Load Cycle**

| Duration of step, h | °C temp. of hot spot | %/h loss of life | % loss of life on step |
|---|---|---|---|
| 12 | 83.5 | ..... | 0 |
| 1 | 106 | 0.015 | 0.015 |
| 1 | 116 | 0.046 | 0.046 |
| 1 | 119 | 0.064 | 0.064 |
| 1 | 123 | 0.095 | 0.095 |
| 2 | 100 | 0.006 | 0.012 |
| 6 | 87.5 | ..... | 0 |
| Total % loss of life per day | | | 0.232 |

**146. Daily overload cycles** consistent with normal life expectancy for air-cooled power transformers in 30°C ambient and for water-cooled power transformers with 25°C ingoing water are given in Table 10-9, which was taken from ANSI C57.92-1962.

**TABLE 10-9. Percent Daily Peak Load for Normal Life Expectancy with 30°C Cooling Air or 25°C Cooling Water**

| Duration of peak load, h | Self-cooled or water-cooled, with % load before peak of | | | Forced-air-cooled up to 133% of self-cooled rating, with % load before peak of | | | Forced-air-cooled over 133% of self-cooled rating or forced-oil-cooled, with % load before peak of | | |
|---|---|---|---|---|---|---|---|---|---|
| | 50% | 70% | 90% | 50% | 70% | 90% | 50% | 70% | 90% |
| 0.5 | 189 | 178 | 164 | 182 | 174 | 161 | 165 | 158 | 150 |
| 1 | 158 | 149 | 139 | 150 | 143 | 135 | 138 | 133 | 128 |
| 2 | 137 | 132 | 124 | 129 | 126 | 121 | 122 | 119 | 117 |
| 4 | 119 | 117 | 113 | 115 | 113 | 111 | 111 | 110 | 109 |
| 8 | 108 | 107 | 106 | 107 | 107 | 106 | 106 | 106 | 105 |

**147. Ambient temperature** affects load capacity by an amount dependent on the type of cooling, as shown in Table 10-10.

**TABLE 10-10. Effect of Ambient Temperature on kVA Capacity**

| Type of cooling | % of rated kVA decrease in capacity for each °C increase over 30°C air or 25°C water | % of rated kVA increase in capacity for each °C decrease under 30°C air or 25°C water |
|---|---|---|
| Self-cooled*........ | 1.5 | 1.0 |
| Water-cooled†........ | 1.5 | 1.0 |
| Forced-air-cooled*........ | 1.0 | 0.75 |
| Forced-oil-cooled*........ | 1.0 | 0.75 |

* From 0 to 50°C air temperature.
† Up to 35°C water temperature.

For ambient temperature of air-cooled transformers use the average value over a 24-h period or 10°C under the maximum temperature during the 24-h period, whichever is higher. For ingoing water temperature use the average value over a 24-h period or 5°C ... temperature during the 24-h period, whichever is higher.

formers owing to their lower cost, greater efficiency, smaller size and weight, and better regulation. Autotransformers may also be obtained with zigzag-connected windings or with delta-connected windings. Both these types are free from triple-harmonic troubles but in general are more expensive.

Delta-connected autotransformers have a possible disadvantage in that they insert a phase shift into the transformation, which means that the system being served must be radial or else it must be served by similar transformations at other points.

**41. Transformer Loading Practice.** Because of the varying load cycle of most transformers, it is customary to permit loading considerably in excess of the transformer nameplate rating. There may be limitations on the transformer imposed by bushings, leads, tap changers, cables, disconnecting switches, circuit breakers, etc. Good engineering design, however, will permit operation without these limitations.

The increase in transformer loading is limited by the effect of temperature on insulation life. High temperature decreases the mechanical strength and increases the brittleness of fibrous insulation and makes transformer failure increasingly likely even though the dielectric strength of the insulation may not be seriously decreased. Overloading should be limited then by giving consideration to the effect on insulation life and transformer life.

**TABLE 17-11. Percent Daily Peak Load for Normal Life Expectancy with 30°C Cooling Air**

| Duration of peak load, h | Self-cooled with % load before peak of | | | Forced-air-cooled up to 133% of self-cooled rating, with % load before peak of | | | Forced-air-cooled over 133% of self-cooled rating, or forced-oil-cooled, with % load before peak of | | |
|---|---|---|---|---|---|---|---|---|---|
| | 50% | 70% | 90% | 50% | 70% | 90% | 50% | 70% | 90% |
| 0.5 | 189 | 178 | 164 | 182 | 174 | 161 | 165 | 158 | 150 |
| 1 | 158 | 149 | 139 | 150 | 143 | 135 | 138 | 133 | 128 |
| 2 | 137 | 132 | 124 | 129 | 126 | 121 | 122 | 119 | 117 |
| 4 | 119 | 117 | 113 | 115 | 113 | 111 | 111 | 110 | 109 |
| 8 | 108 | 107 | 106 | 107 | 107 | 106 | 106 | 106 | 105 |

For recurring loads, such as the daily load cycles, the transformer would be operated for normal life expectancy. For emergencies, either planned or accidental, loading would be based on some percentage loss of life.

In a typical case for a failure of part of the electrical system, a 2.5% loss of life per day for a transformer may be acceptable. Loading recommendations based on the evaluation of the loss of insulation life as affected by temperature are contained in USAS C57.92-1962, Guide for Loading Oil-immersed Power Transformers with 55°C Average Winding Rise Insulation Systems. *NEMA Publ.* TR98-1964 contains corresponding recommendations for loading power transformers with 65°C average winding rise insulation systems. USAS C57.92-1962 Guide states that an average loss of life of 1% per year or 5% in any one emergency operation is considered a reasonable loss of life.

Daily overload cycles consistent with normal life expectancy for air-cooled power transformers at 30°C ambient are given in Table 17-11 which is a condensation of data taken from USAS C57.92-1962, Section 92-01.250. For a listing of transformer loading above normal with some sacrifice of life expectancy, data given in *NEMA Publ.* TR 98-1964, Part 3, are condensed in Table 17-12.

Ambient temperature affects load capacity by an amount dependent on the type of cooling as shown in Tables 17-11 and 17-12. For changes from this average ambient temperature, transformer ratings may be adjusted as shown in Table 17-13. The table applies to both the 55°C and the 65°C average winding-temperature-rise transformers. For the ambient temperature of air-cooled transformers, use the average value over a 24-h period or 10°C under the maximum during the 24-h period, whichever is higher.

The following temperature and load limitations are generally applied to transformers. The temperature of the top oil should never exceed 100°C. The maximum hot-spot winding temperature should not exceed 150°C for 55°C rise transformers or 180°C for 65°C rise transformers. Short-time peak loading for ½ h or more should not exceed 200%

**TABLE 17-12. Allowable Peak Loads (In Multiples of Maximum Nameplate Rating) for Moderate Sacrifice of Life Expectancy with 30°C Cooling Air***

| Duration of peak load, h | Hottest-spot temperature reached, °C | Life loss in percent not more than | Self-cooled (OA) with % load before peak of | | | | Forced-air-cooled (OA/FA) up to 133% of self-cooled rating with % load before peak of | | | | Forced-air-cooled (OA/FA/FA) over 133% of self-cooled rating or forced-oil-cooled (FOA or OA/FOA/FOA) with % load before peak of | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 50% | 70% | 90% | 100% | 50% | 70% | 90% | 100% | 50% | 70% | 90% | 100% |
| ½ | 171 | 0.25 | 2.00 | 2.00 | 2.00 | 1.96 | 2.00 | 1.95 | 1.85 | 1.80 | 1.64 | 1.60 | 1.54 | 1.51 |
| | 180 | 0.50 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 1.95 | 1.90 | 1.69 | 1.66 | 1.60 | 1.57 |
| 1 | 163 | 0.25 | 1.96 | 1.89 | 1.80 | 1.74 | 1.77 | 1.72 | 1.65 | 1.61 | 1.47 | 1.45 | 1.49 | 1.39 |
| | 180 | 1.00 | 2.00 | 2.00 | 1.99 | 1.94 | 1.93 | 1.88 | 1.81 | 1.78 | 1.57 | 1.55 | 1.52 | 1.50 |
| 2 | 155 | 0.25 | 1.68 | 1.63 | 1.57 | 1.53 | 1.53 | 1.50 | 1.47 | 1.44 | 1.33 | 1.32 | 1.31 | 1.30 |
| | 171 | 1.00 | 1.83 | 1.79 | 1.71 | 1.64 | 1.66 | 1.64 | 1.60 | 1.58 | 1.42 | 1.41 | 1.39 | 1.39 |
| | 180 | 2.00 | 1.91 | 1.83 | 1.71 | 1.64 | 1.74 | 1.71 | 1.65 | 1.61 | 1.47 | 1.46 | 1.44 | 1.43 |
| 4 | 147 | 0.25 | 1.44 | 1.41 | 1.39 | 1.37 | 1.35 | 1.34 | 1.33 | 1.32 | 1.24 | 1.23 | 1.23 | 1.23 |
| | 163 | 1.00 | 1.55 | 1.52 | 1.47 | 1.44 | 1.47 | 1.46 | 1.45 | 1.45 | 1.32 | 1.32 | 1.32 | 1.32 |
| | 180 | 4.00 | 1.55 | 1.52 | 1.47 | 1.44 | 1.51 | 1.50 | 1.47 | 1.46 | 1.40 | 1.40 | 1.39 | 1.39 |
| 8 | 139 | 0.25 | 1.28 | 1.27 | 1.27 | 1.26 | 1.24 | 1.24 | 1.24 | 1.24 | 1.18 | 1.18 | 1.18 | 1.18 |
| | 155 | 1.00 | 1.38 | 1.37 | 1.36 | 1.36 | 1.36 | 1.36 | 1.36 | 1.36 | 1.27 | 1.27 | 1.27 | 1.27 |
| | 171 | 4.00 | 1.38 | 1.37 | 1.36 | 1.36 | 1.42 | 1.42 | 1.41 | 1.41 | 1.35 | 1.35 | 1.35 | 1.35 |

*Based on capability tables in *NEMA Publ.* TR98, Part 3.

For forced-air-cooled transformers, the peak loads are calculated on the basis of all cooling being in use during the period preceding the peak load. When operating without fans, use the tables for OA transformers.

Differences in cooling methods used with forced-oil-cooled transformers result in differences in peak-load-carrying ability. Consult the manufacturer before applying loads above the values given in the table.

rating. At abnormally high temperatures it may be necessary to remove some oil in order to avoid overflow or excessive pressure.

**42. Surge Protection.** A substation should be designed to include safeguards against the hazards of abnormally high voltage surges that can appear across the insulation of electrical equipment in the station. The most severe overvoltages are caused by lightning strokes and by switching surges.

The main methods to prevent these overvoltages from causing insulation failures include:

*a.* Use of surge arresters
*b.* Equipment neutral grounding
*c.* Proper selection of equipment impulse insulation level
*d.* Proper selection and coordination of equipment basic insulation levels
*e.* Careful study of switching-surge levels that can appear in the substation

The main device used to prevent dangerous overvoltages, flashovers, and serious damage to equipment is the surge arrester. The surge arrester conducts high surge currents, such as can be caused by a lightning stroke, harmlessly to ground and thus

**TABLE 17-13. Effect of Ambient Temperature on kVA Capacity**

| Type of cooling | % of rated kVA decrease in capacity for each °C increase over 30°C air | % of rated kVA increase in capacity for each °C decrease under 30°C |
|---|---|---|
| Self-cooled—OA | 1.5 | 1.0 |
| Forced-air-cooled—OA/FA, OA/FA/FA | 1.0 | 0.75 |
| Forced-air-cooled—FOA, OA/FOA/FOA | 1.0 | 0.75 |

prevents excessive overvoltages from appearing across equipment insulation. For a detailed description of the characteristics and application of arresters, refer to Sec. 27.

The important consideration in applying surge arresters and in selecting equipment insulation levels depends greatly on the method of grounding used. Systems are considered to be effectively grounded when the coefficient of grounding does not exceed 80%. Similarly, systems are noneffectively grounded or ungrounded when the coefficient of grounding exceeds 80%.

A value not exceeding 80% is obtained approximately when, for all system conditions, the ratio of zero sequence reactance to positive sequence reactance ($X_0/X_1$) is positive and less than 3, and the ratio of zero sequence resistance to positive sequence reactance ($R_0/X_1$) is positive and less than 1. What this says in effect is that if neutrals are grounded solidly everywhere and if a ground occurs on one of the conductors then the voltage that can appear on the healthy phases cannot exceed 80% of normal phase-to-phase voltage.

Thus the coefficient of grounding is defined as the ratio of maximum sustained line-to-ground voltage during faults to the maximum operating line-to-line voltage. On many HV and EHV systems the coefficient of grounding may be as low as 70%.

Surge arrester ratings are normally selected on the basis of the coefficient of grounding; thus, for effectively grounded systems the 80% arrester is selected. For example, a 115-kV system (maximum operating voltage equals 121 kV) can use a 97-kV arrester, that is, 80% of 121 kV, when operating on a solidly grounded system. It should be noted that other factors such as resonant conditions, system switching, etc., could increase the value of the coefficient of grounding and thus should be studied in each individual system.

The impulse insulation level of a piece of equipment is a measure of its ability to withstand impulse voltage. It is the crest value, in kilovolts, of the wave of impulse voltage that the equipment must withstand. However, at EHV the switching-surge insulation level may be lower than the corresponding impulse level and thus the switching-surge level becomes the dominant factor in establishing insulation levels.

Basically the coordination of insulation in a substation means the use of no higher-rated arrester than required to withstand the 60-Hz voltage and the choice of equipment insulation levels that can be protected by the arrester. Careful study of switching-surge

levels that can occur at the substation as
analyzer studies can also be used to deter
and switching-surge strength required in

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**Exhibit ____ (AG-PLC-20)**
**Excerpts Concerning Dependence of Underground Line Capacity on Energy Loads**

**(4 pages, including this cover page)**

# UNDERGROUND SYSTEMS REFERENCE BOOK

PREPARED BY AN EDITORIAL STAFF
OF THE EDISON ELECTRIC INSTITUTE
TRANSMISSION AND DISTRIBUTION COMMITTEE

1957

*Published by the*

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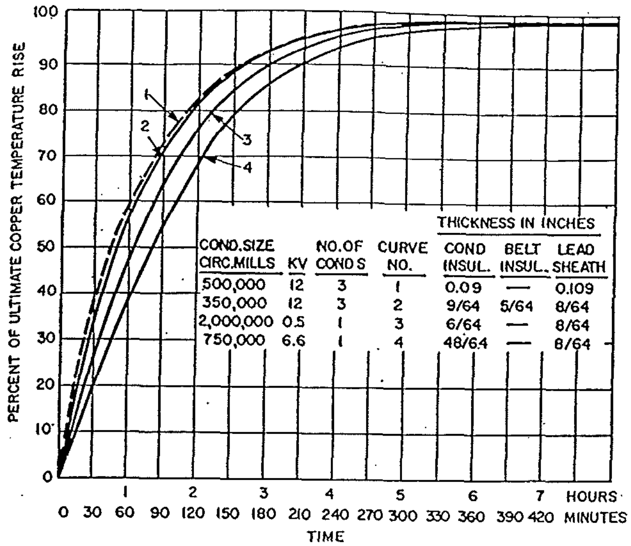


Fig. 10-28 — Time-temperature rise characteristics for paper-insulated cables.

$T_a$ = ambient temperature, deg C
$W_c$ = conductor loss (including skin effect and proximity effect), watts per foot
$W_s$ = sheath loss (including circulating current loss and eddy current loss), watts per foot
$W_a$ = armor loss (including circulating current loss, hysteresis loss and eddy current loss), watts per foot
$W_D$ = dielectric loss, watts per foot
$R_i$ = thermal resistance of the cable insulation, thermal ohms per foot
$R_j$ = thermal resistance of the jacket between sheath and armor, or thermal resistance of pipe covering for pipe cable, thermal ohms per foot
$R_e$ = thermal resistance of the soil, thermal ohms per foot
$R_s$ = thermal resistance from outer surface of the cable to inner surface of the pipe, thermal ohms per foot (for pipe cable only)
= zero for other types of buried cable
$R_t$ = total thermal resistance, thermal ohms

$$= \left[R_i + R_s + \left(1 + \frac{W_s}{W_c}\right) \times R_j + \left(1 + \frac{W_s}{W_c} + \frac{W_a}{W_c}\right) R_e\right]$$

$R_c$ = conductor resistance, including skin effect and proximity effect, ohms per foot

### *Thermal Transients*

Underground power cables almost always operate under variable loading. In order to simplify the problem, temperatures and load capabilities are usually calculated on the basis of some more or less equivalent steady load. Such approximate methods are frequently inadequate. Cases arise where it is desirable to establish load capabilities for longer periods than those for short circuit conditions but of shorter duration than steady state conditions. Precise solutions of the temperature transients in this range are long and involved. Two excellent methods of calculating have been presented[47, 48] but do not lend themselves to presentation here. Fig. 10-28, however, shows results of thermal transient tests on several sizes of impregnated-paper-insulated lead-covered cables. From curves of this kind conservative cable attainment factors may be estimated that are sufficiently accurate for most problems at hand.

Thermal transients of the conduit system may also enter into the problem. Typical curves of transient conduit temperature rise are shown in Fig. 10-29. These curves were determined from test results[7, 49] for conduits buried in clay soil and having approximately 3 ft of cover. Conduits buried deeper will take longer to attain steady state temperature rise. A theoretical approach was presented by J. H. Neher.[5] Fig. 10-30 gives theoretical attainment factors for cylindrical radiators using this approach.

## Buried Cables

### *Isolated Cable*

The current-carrying capacity of an isolated buried cable may be calculated from Equation 1 following:

$$I = \sqrt{\frac{T_c - T_a - T_d}{R_c R_t}} \quad \ldots\ldots\ldots\ldots (1)$$

where: $I$ = load current, amperes
$T_c$ = permissible copper temperature, deg C
$T_d$ = temperature rise due to dielectric loss, deg C
$= W_D (R_i/2 + R_s + R_j + R_e)$

For buried cables, the ratios $W_s/W_c$ and $W_a/W_c$ are calculated in the same way as they would be for cables in free air or in ducts, with the same spacing and arrangement as is used in the actual buried cable installation. For three-conductor cables, $W_s$ and $W_a$ are taken equal to zero and $R_c$ is multiplied by the a-c/d-c ratio. For pipe cables, $W_a$ is taken as zero and

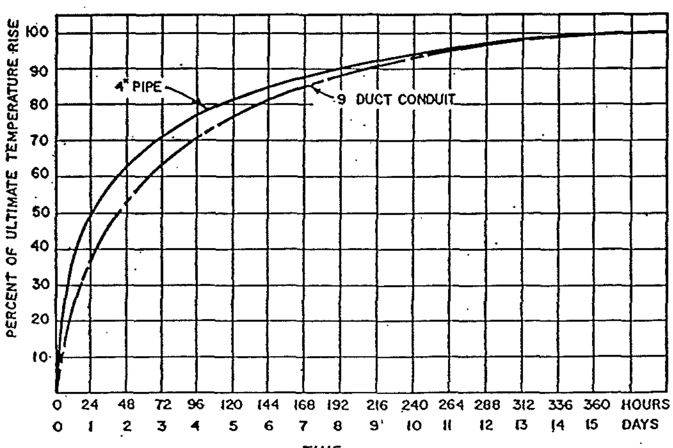


Fig. 10-29—Time-temperature rise characteristics for pipe and conduit.

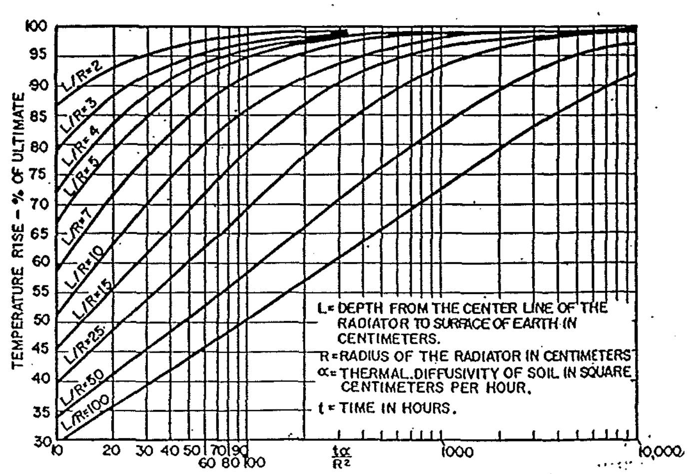


Fig. 10-30—Attainment factors for cylindrical heat radiators.

### Table XXXV—Single-Conductor, Paper-Insulated, Solid-Type Cable (Rating, 35,000 Volts)

| Conductor Size, AWG or MCM | Number of Equally Loaded Cables in Duct Bank — Three | | | Six | | | Nine | | | Twelve | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Per Cent Load Factor | | | | | | | | | | | |
| | 50 | 75 | 100 | 50 | 75 | 100 | 50 | 75 | 100 | 50 | 75 | 100 |
| | Normal Operation—Copper Temperature 70 C, Amperes Per Conductor, Concentric Conductor* | | | | | | | | | | | |
| 2/0 | 251 | 239 | 224 | 242 | 224 | 205 | 234 | 211 | 190 | 226 | 200 | 179 |
| 250 | 367 | 345 | 322 | 352 | 321 | 294 | 337 | 303 | 270 | 324 | 286 | 253 |
| 500 | 551 | 514 | 476 | 524 | 474 | 429 | 500 | 442 | 392 | 479 | 416 | 364 |
| 1000 | 832 | 766 | 701 | 783 | 698 | 624 | 741 | 646 | 564 | 706 | 601 | 520 |
| 1500 | 1036 | 949 | 859 | 972 | 856 | 760 | 914 | 788 | 682 | 865 | 730 | 626 |
| 2000 | 1197 | 1088 | 981 | 1115 | 975 | 860 | 1045 | 893 | 770 | 985 | 824 | 704 |
| | Compact Segmental Conductor | | | | | | | | | | | |
| 1000 | 853 | 786 | 720 | 803 | 718 | 641 | 760 | 663 | 581 | 722 | 618 | 534 |
| 2000 | 1293 | 1175 | 1061 | 1203 | 1055 | 929 | 1127 | 965 | 834 | 1059 | 890 | 759 |
| 3000 | 1630 | 1465 | 1312 | 1502 | 1304 | 1137 | 1399 | 1182 | 1013 | 1308 | 1085 | 919 |
| 4000 | 1896 | 1690 | 1505 | 1737 | 1493 | 1294 | 1609 | 1349 | 1149 | 1496 | 1230 | 1036 |

Emergency Operation—Copper Temperature 85 C**
These values may be obtained by multiplying the above tabular values by 1.11.

* Abstracted from IPCEA Publication P-29-226.
** Based on 100 hr in any 12-month period.

### Table XXXVI—Three-Conductor, Paper-Insulated, Solid-Type Cable, Belted (Rating, 7500 Volts)

| Conductor Size, AWG or MCM | Number of Equally Loaded Cables in Duct Bank — One | | | Three | | | Six | | | Twelve | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Per Cent Load Factor | | | | | | | | | | | |
| | 50 | 75 | 100 | 50 | 75 | 100 | 50 | 75 | 100 | 50 | 75 | 100 |
| | Normal Operation—Copper Temperature 83 C*, Amperes Per Conductor, Round or Sector Conductors | | | | | | | | | | | |
| 6 | 80 | 77 | 74 | 76 | 72 | 67 | 74 | 67 | 62 | 69 | 60 | 53 |
| 4/0 | 270 | 258 | 243 | 255 | 235 | 214 | 241 | 213 | 190 | 218 | 184 | 159 |
| 500 | 454 | 429 | 399 | 423 | 381 | 341 | 392 | 340 | 298 | 348 | 288 | 245 |
| 750 | 576 | 540 | 497 | 532 | 473 | 418 | 489 | 418 | 363 | 428 | 350 | 295 |

Emergency Operation—Copper Temperature 94 C**
These values may be obtained by multiplying the above tabular values by 1.07.

* Abstracted from IPCEA Publication P-29-226.
** Based on 100 hr in any 12-month period.

### Table XXXVII—Three-Conductor, Paper-Insulated, Solid-Type Cable, Belted (Rating, 15,000 Volts)

| Conductor Size, AWG or MCM | Number of Equally Loaded Cables in Duct Bank — One | | | Three | | | Six | | | Twelve | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Per Cent Load Factor | | | | | | | | | | | |
| | 50 | 75 | 100 | 50 | 75 | 100 | 50 | 75 | 100 | 50 | 75 | 100 |
| | Normal Operation—Copper Temperature 75 C*, Amperes Per Conductor, Round or Sector | | | | | | | | | | | |
| 4 | 99 | 96 | 92 | 74 | 89 | 83 | 91 | 83 | 75 | 85 | 73 | 64 |
| 4/0 | 257 | 245 | 232 | 242 | 222 | 202 | 228 | 201 | 179 | 205 | 173 | 149 |
| 500 | 429 | 406 | 377 | 399 | 359 | 321 | 396 | 319 | 280 | 326 | 269 | 229 |
| 750 | 543 | 510 | 468 | 499 | 444 | 393 | 458 | 391 | 341 | 399 | 326 | 275 |

Emergency Operation—Copper Temperature 87 C**
These values may be obtained by multiplying the above tabular values by 1.09.

* Abstracted from IPCEA Publication P-29-226.
** Based on 100 hr in any 12-month period.

### Table XXXVIII—Three-Conductor, Paper-Insulated, Solid-Type Cable, Shielded (Rating, 15,000 Volts)

| Conductor Size, AWG or MCM | Number of Equally Loaded Cables in Duct Bank — One | | | Three | | | Six | | | Twelve | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Per Cent Load Factor | | | | | | | | | | | |
| | 50 | 75 | 100 | 50 | 75 | 100 | 50 | 75 | 100 | 50 | 75 | 100 |
| | Normal Operation—Copper Temperature 81 C*, Amperes Per Conductor | | | | | | | | | | | |
| 4 | 120 | 115 | 107 | 114 | 104 | 95 | 108 | 95 | 85 | 96 | 83 | 72 |
| 4/0 | 295 | 281 | 261 | 276 | 250 | 223 | 257 | 224 | 196 | 227 | 189 | 162 |
| 500 | 487 | 450 | 418 | 446 | 399 | 350 | 410 | 350 | 303 | 358 | 292 | 247 |
| 750 | 606 | 562 | 514 | 551 | 485 | 426 | 502 | 423 | 365 | 432 | 348 | 293 |

Emergency Operation—Copper Temperature 96 C**
These values may be obtained by multiplying the above tabular values by 1.07.

* Abstracted from IPCEA Publication P-29-226.
** Based on 100 hr in any 12-month period.

# Exhibit ____ (AG-PLC-21)
# Excerpt from NEES Distribution System Planning Guidelines

**(3 pages, including this cover page)**

1. SCOPE - This STANDARD covers method of selecting size of cables required for underground residential distribution secondaries.

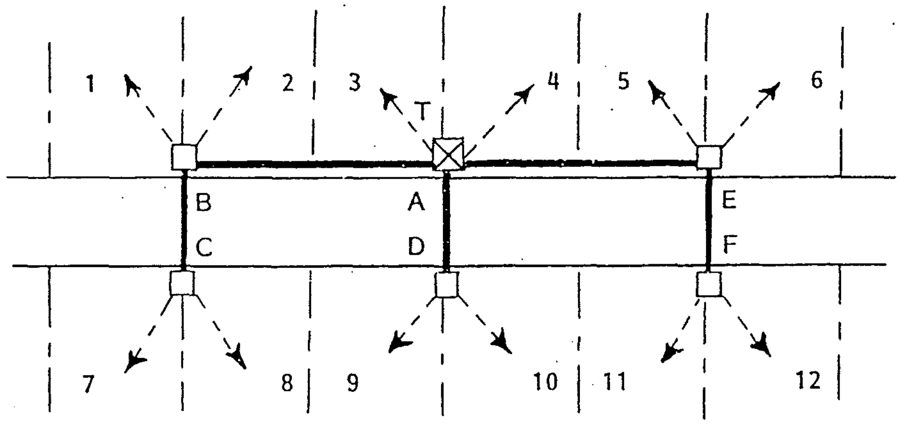


FIG. 1 - TWO-WAY STREET - SAMPLE LAYOUT

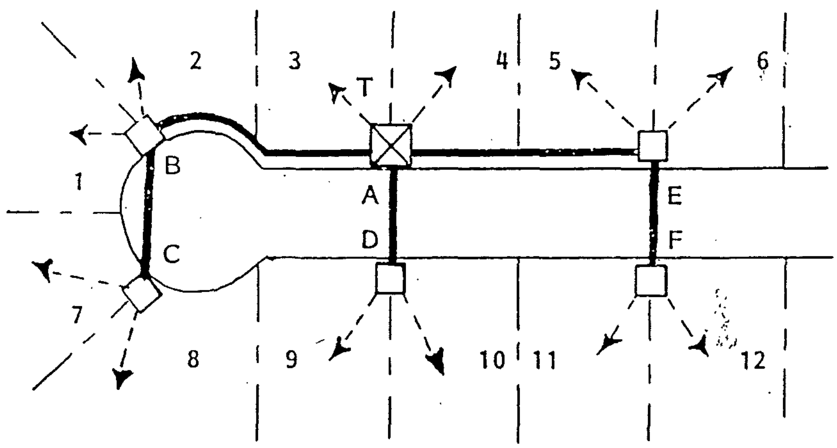


FIG. 2 - DEAD-END STREET - SAMPLE LAYOUT

2. PRELIMINARY LAYOUT - Make layout assigning number of homes per transformer and loads per lot (Figures 1 and 2).

a. From point A to the left add load of lots 1, 2, 7 and 8.
b. Measure distance in feet between points A and B.
c. Plot point on chart (Fig. 3) kVA versus distance and select proper size of secondary cable for A-B. If point falls within the limits of a cable size, proceed with Step (d). If point falls on limit of 4/0 cable, then use 350 kcmil cable to allow for drop between points B and C, and proceed with Step (d).
d. Measure distance between B and C. Add loads of lots 7 and 8, and select cable size.

Issue C - January 1984 - No Change

STD 2521 OVERHEAD TRANSFORMER APPLICATION

B
Issue

Load and Voltage Management

New England Electric

1. NEW CONSTRUCTION - The following tables are recommended to give good electrical characteristics as well as an economical design.

a) Low Use Customers - 1.0 kVA/cust. (250 kW-hrs/2 month period) (lighting, small appliances and refrigerator) ± 150 ft. spans 1/0 aluminum triplex - secondary not to exceed 2 sections each way (± 600 ft.)

| No. Cust. | Size Transf. | Max. Init. % Load-Winter | Coincidence Factors |
|---|---|---|---|
| 1 - 20 | 10 kVA | 92% | 1 - .46 |

b) Medium Use Customers - 2.4 kVA/cust. (600 kW-hrs/2 month period) (bronze medallion home - all uses except electric heat) ± 150 ft. spans 1/0 aluminum triplex - secondary not to exceed 2 sections each way (± 600 ft.)

| No. Cust. | Size Transf. | Max. Init. % Load-Winter | Coincidence Factors |
|---|---|---|---|
| 1 - 8 | 10 kVA | 105% | 1 - .55 |
| 9 - 12 | 15 kVA | 96% | .53 - .50 (preferred design) |
| 13 - 20 | 25 kVA | 88% | .49 - .46 |

c) High Use Customers - 15.0 kVA/cust. (7500 kW-hrs/2 month period) (gold medallion home - all appliances plus electric heat) ± 150 ft. spans 1/0 aluminum triplex - secondary not to exceed 2 sections each way (± 600 ft.)

| No. Cust. | Size Transf. | Max. Init. % Load-Winter | Coincidence Factors |
|---|---|---|---|
| 1 - 8 | 50 kVA | 132% | 1 - .55 |

2. EXISTING CONSTRUCTION OR CONVERSIONS TO A HIGHER VOLTAGE - Overhead transformers and/or secondaries - it is permissable to load overhead residential distribution transformers to 200% winter peak and 160% summer peak as determined by the Transformer Load Management Program, provided secondaries are adequate to maintain required voltage. If a transformer is suspected of supplying appreciable air conditioning load, the 160% summer loading of the Load Management Program does not apply and field testing should be utilized. When these limits are exceeded, the secondary design should be reviewed and if necessary the crib should be reconductored and/or redesigned so that it is not more than 300 feet in length in either direction from the transformer. This may require the installation of additional transformers.

Issue B - January 1979 - No Change

**Exhibit ____ (AG-PLC-22)**
**Excerpts Concerning Diversity of Customer Loads at the Distribution Level**

**(13 pages, including this cover page)**

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# Standard Handbook for Electrical Engineers


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*General Manager and Executive Director (Retired), Institute of Electrical and Electronics Engineers; formerly Vice President—Research, Philco Corporation, President of the Institute of Radio Engineers, Editor of the Proceedings of the IRE; Fellow of the IEEE; Fellow of the IEE (London); Eminent Member, Eta Kappa Nu; Member of the National Academy of Engineering*

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Eleventh Edition


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Sydney Tokyo Toronto

## Demand and Diversity Factors

260. **Demand Factor.** The ratio of maximum demand to total load connected, expressed as a percentage, is termed the demand factor of an installation. For example, if a residence having equipment connected with a total rating of 6000 W has a maximum demand of 3300 W, it has a demand factor of 55%. Demand factors of various types of large loads are helpful in designing systems, particularly those in buildings. As an example, a single household electric clothes dryer, of course, has a demand factor of 100%, but 25 dryers in a group have a demand factor of 33%. Similarly, three to five all-electric apartments in a multifamily dwelling have a demand factor of 45%. The lower the demand factor the less system capacity required to serve the connected load. However, summer air conditioning and winter electric heating are loads that make for high demand factors.

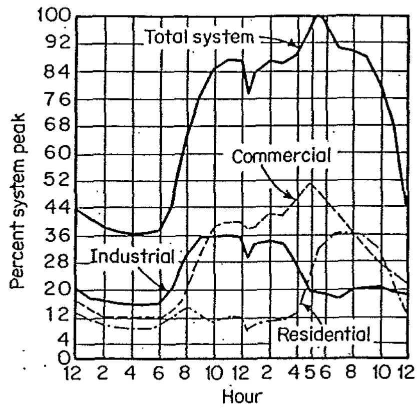


**Fig. 18-67.** Characteristic metropolitan load pattern.

261. **Coincidence or Diversity Factor.** The coincidence factor is defined as the ratio of the maximum demand of the load as a whole, measured at its supply point, to the sum of the maximum demands of the component parts of a load. The diversity factor is the reciprocal of the coincidence factor. Coincidence factors can be applied to known consumer demands for estimating the loading of distribution transformers, lines, and other facilities. Coincidence factors for residential consumers can vary over a wide range for different types of consumers. The coincidence factor for a large group of consumers with no major appliance might be as low as 30%, whereas a group of electric-heating consumers might be as high as 90%.

262. **Diversity between Classes of Users.** The daily-load curve of a utility is a composite of demands made by various classes of users. The load curve on the day of maximum total system peak occurs when class loads gang up to create this maximum demand for the year. This is not necessarily the day, and usually is not the day, of any particular class peak. Class load curves on the day of system peak are illustrated in Fig. 18-67.

Air-conditioning loads have shifted these curves for many systems to cause daytime peaks during hot weather in the summer. Electric house heating builds heavy morning and evening loads during cold weather in the winter.

263. **Diversity in the Feeder System.** The diversity of demands by transformers on a radial feeder makes the maximum load on the feeder less than the sum of the transformer loads. The diversity factors of a feeder vary greatly depending upon load conditions. Some

**TABLE 18-26. Diversity Factors**

| Elements of system between which diversity factors are stated: | Diversity factors for | | | |
|---|---|---|---|---|
| | Residence lighting | Commercial lighting | General power | Large users |
| Between individual users | 2.0 | 1.46 | 1.45 | |
| Between transformers | 1.3 | 1.3 | 1.35 | 1.05 |
| Between feeders | 1.15 | 1.15 | 1.15 | 1.05 |
| Between substations | 1.1 | 1.10 | 1.1 | 1.1 |
| From users to transformer | 2.0 | 1.46 | 1.44 | |
| From users to feeder | 2.6 | 1.90 | 1.95 | 1.15 |
| From users to substation | 3.0 | 2.18 | 2.24 | 1.32 |
| From users to generating station | 3.29 | 2.40 | 2.46 | 1.45 |

typical diversity factors are given in Table 18-26. The diversity factor of lighting feeders ranges from 1.1 to 1.5, while that of mixed light-and-power feeders is likely to be 1.5 to 2 or more. At the substation there is also a diversity factor of 1.05 to 1.25 between the sum of feeder maxima and the substation maximum. A large system has a further diversity factor between substations of 1.05 to 1.25.

**264. Total diversity factors** in a large system are somewhat as in Table 18-26.

## Distribution Economics

**265. Economic Comparisons.** The most straightforward and generally applicable technique to use in distribution-system investment problems is that of making economic comparisons on the basis of the present value of all future annual costs. That is, the economic choice is the one with the lowest present value of all future costs. With this as a criterion, the procedure for making an economic comparison between alternatives is a simple two-step operation, that is:

*a.* Estimate for each alternative the annual costs for each year.

*b.* If annual costs are not uniform, calculate their present value.

**266. Time Value of Money.** Money does have time value, and rent or interest on its use has to be paid. It is obvious that an alternative which requires the least expenditure immediately would be best, everything else being equal.

The process of taking money and finding its equivalent value at some future time is called a "future worth" or "future value" calculation. This calculation is the same as that used in determining the effect of compound interest.

If 8% is the established interest rate, then \$100 today is equivalent to \$100 $(1 + 0.08)$ or \$108 a year from now, and $100\,(1 + 0.08) + 100\,(1 + 0.08) \times 0.08 = 100\,(1 + 0.08)^2$ 2 years from now, and $100\,(1 + 0.08)^{10}$ 10 years from now. The expression $(1 + i)^n$ is called the compound amount factor, where $i$ is the interest rate and $n$ is the number of years. These factors and others discussed later are readily available for various interest rates and number of years in economic books such as *Principles of Engineering Economy* by Eugene L. Grant.

Hence, to find the future worth of \$100, 10 years later in the above example, first, look up the compound amount factor in the 8% interest table for year 10, then multiply it by 100. The compound amount factor for this case is 2.159 and the future worth calculates to be 100(2.159) = \$215.90.

The process of finding the equivalent value of money at some earlier time is called a "present worth" or "present value" operation.

The present worth calculation is the reverse of the future worth calculation. If \$100 today has a future worth a year from now of \$108, then we can also say that \$108 a year from now has a present worth of \$100 today. The present worth factor is the inverse of the future worth factor, and it also may be found in interest tables. Since the future worth factor for $n$ years is $(1 + i)^n$, where $i$ is the interest rate, the present worth factor is $1/(1 + i)^n$.

To determine the present worth, as of today, of a \$100 cost anticipated to be incurred 2 years from now where the interest rate is 8%, first the present worth factor of 0.8573 is obtained from interest tables. Then multiplying this factor by \$100 gives the present worth of \$100 (0.8573) = \$85.73.

Formulas for calculating the compound interest factors and a graphical interpretation of these factors are shown in Fig. 18-68.

**267. Annual Charges.** It is desirable to have a convenient method of calculating the annual costs of capital investment made in an alternative scheme. Fortunately, this can be done by using a level carrying charge which is expressed as a percentage of the original investment.

The total revenue requirements of a piece of equipment are the sum of the annual charges for:

*a.* Return on investment.

*b.* Depreciation.

The transformer secondary and service size required to supply a multi-family electric heated development is determined as follows:

1. Determine the dwelling unit demand using the formula in Table I. The demand is based solely on area and applies to all types of electric heat/heat pump and includes air conditioning and major appliances such as ranges, water heaters, dryers, etc.

2. Determine the diversity factor for the number of dwelling units in a building (or other logical grouping) from Table II.

3. Calculate building or group demand using formula in Table III.

4. Select the transformer size from Table IV.

5. Using Table V, pick the smallest secondary and/or service combination that will carry the load and stay within a 2% voltage drop.
   See DTR 54.032 for an example of calculations above.

I

**Demand Per Dwelling Unit**

$$\text{Unit Peak Demand (KVA)} = \frac{\text{Area Of Unit (Sq Ft)}}{100}$$

II

| Diversity Factor (DF) For Above Demands | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No Of Units | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 Or More |
| DF | .88 | .82 | .79 | .77 | .76 | .74 | .73 | .72 | .72 | .71 | .70 | .69 |

III

**Demand Of Entire Building Or Grouping**

Demand = N x DF x KVA

Where: N = Number Of Units
DF = Diversity Factor For N Units
KVA = Unit Peak Demand

IV

| Transformer Size For Electric Heat | | | | | |
|---|---|---|---|---|---|
| KVA Demand | 37 | 75 | 112 | 150 | 250 |
| Size-KVA | 25 | 50 | 75 | 100 | 167 |

V

**Voltage Drop (VD) In Secondary And/Or Service**

% VD = (AxLxKVA) Of Secondary + (AxLxKVA) Of Service

Where: A = Cable Voltage Drop Factor
L = Secondary Or Service Cable Length
KVA = Secondary Or Service Peak Demand

Limit Total Voltage Drop To 2%.

| Max KVA | 48 | 72 | 96 | 125 | 168 |
|---|---|---|---|---|---|
| A | 0.00062 | 0.00033 | 0.00022 | 0.00017 | 0.00011 |
| Cable | 1/0 Al | 4/0 Al | 350 Al | 2X4/0 Al | 2X350 Al |

| REVISION | 10 | 9 | 8 | 7 | 6 | 5 | 4 | 3 | 2 | 1 | ORIGINAL ISSUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| DATE | | | | | | | | | | 6/22/82 | 1/4/80 |
| APPROVED BY | | | | | | | | | | | |

DIRECT BURIED MULTI-FAMILY ELECTRIC HEAT/HEAT PUMP TRANSFORMER, SECONDARY AND SERVICE SELECTOR GUIDE

# UNDERGROUND RESIDENTIAL DISTRIBUTION

# LOADING & CABLE PARAMETERS

POTOMAC ELECTRIC POWER COMPANY

POTOMAC ELECTRIC POWER COMPANY
ENGINEERING DEPARTMENT

PROJECT Diversified Loads in URD Subdivisions

PREPARED ____ DATE 4/01/85

CHECKED BY ____ DATE ____

SUBJECT TABLE I - Diversified Demand (KVA/House)

| No. of | | Electric Air Conditioning (HP) (Gas/Oil Heat) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Houses | None * | 1 1/2 | 2 | 2 1/2 | 3 | 3 1/2 | 4 | 5 | 7 1/2 |
| 1 | 6.40 | 8.80 | 9.60 | 10.70 | 11.30 | 12.20 | 13.00 | 14.70 | 19.00 |
| 2 | 5.73 | 8.30 | 9.10 | 10.20 | 10.80 | 11.60 | 12.10 | 13.20 | 17.30 |
| 3 | 4.76 | 6.50 | 7.30 | 8.40 | 9.10 | 9.70 | 10.40 | 11.80 | 15.00 |
| 4 | 4.12 | 5.00 | 5.80 | 6.90 | 7.50 | 8.30 | 8.88 | 10.03 | 13.80 |
| 5 | 3.74 | 4.22 | 5.00 | 6.00 | 6.54 | 7.44 | 7.94 | 9.52 | 13.20 |
| 6 | 3.48 | 3.88 | 4.55 | 5.45 | 6.03 | 6.90 | 7.48 | 9.07 | 12.80 |
| 7 | 3.28 | 3.63 | 4.26 | 5.10 | 5.66 | 6.47 | 7.13 | 8.70 | 12.50 |
| 8 | 3.12 | 3.45 | 4.02 | 4.80 | 5.40 | 6.17 | 6.86 | 8.45 | 12.30 |
| 9 | 3.00 | 3.31 | 3.84 | 4.60 | 5.18 | 5.90 | 6.68 | 8.25 | 12.10 |
| 10 | 2.90 | 3.20 | 3.70 | 4.40 | 5.00 | 5.70 | 6.50 | 8.10 | 12.00 |
| 11 | 2.78 | 3.07 | 3.58 | 4.10 | 4.80 | 5.49 | 6.29 | 7.90 | 11.90 |
| 12 | 2.68 | 2.97 | 3.48 | 4.05 | 4.65 | 5.30 | 6.11 | 7.72 | 11.80 |
| 13 | 2.60 | 2.88 | 3.38 | 3.90 | 4.53 | 5.15 | 6.00 | 7.60 | 11.73 |
| 14 | 2.54 | 2.82 | 3.30 | 3.80 | 4.42 | 5.04 | 5.87 | 7.48 | 11.66 |
| 15 | 2.49 | 2.77 | 3.25 | 3.70 | 4.30 | 4.93 | 5.75 | 7.38 | 11.60 |
| 16 | 2.44 | 2.73 | 3.18 | 3.63 | 4.22 | 4.85 | 5.66 | 7.28 | 11.53 |
| 17 | 2.40 | 2.69 | 3.13 | 3.56 | 4.26 | 4.78 | 5.60 | 7.19 | 11.50 |
| 18 | 2.36 | 2.66 | 3.08 | 3.50 | 4.12 | 4.71 | 5.51 | 7.10 | 11.46 |
| 19 | 2.33 | 2.63 | 3.04 | 3.44 | 4.06 | 4.65 | 5.45 | 7.04 | 11.43 |
| 20 | 2.30 | 2.60 | 3.00 | 3.40 | 4.00 | 4.60 | 5.40 | 7.00 | 11.40 |
| 30 | 2.13 | 2.45 | 2.77 | 3.10 | 3.70 | 4.27 | 5.03 | 6.60 | 11.00 |
| 40 | 2.02 | 2.37 | 2.64 | 2.93 | 3.52 | 4.10 | 4.88 | 6.45 | 10.75 |
| 50 | 1.96 | 2.33 | 2.58 | 2.84 | 3.38 | 4.00 | 4.81 | 6.42 | 10.54 |
| 60 | 1.94 | 2.32 | 2.54 | 2.78 | 3.25 | 3.95 | 4.77 | 6.40 | 10.40 |
| 70 | 1.93 | 2.32 | 2.53 | 2.75 | 3.20 | 3.90 | 4.73 | 6.38 | 10.30 |
| 80 | 1.92 | 2.31 | 2.52 | 2.73 | 3.13 | 3.87 | 4.69 | 6.34 | 10.20 |
| 90 | 1.91 | 2.31 | 2.51 | 2.71 | 3.05 | 3.84 | 4.65 | 6.31 | 10.10 |
| 100 | 1.90 | 2.30 | 2.50 | 2.70 | 3.00 | 3.80 | 4.63 | 6.30 | 10.00 |
| 500 | 1.86 | 2.00 | 2.20 | 2.40 | 2.70 | 3.52 | 4.34 | 6.00 | 8.80 |

* Includes lights, refrigerator, range, hot water heater and miscellaneous appliances

FORM 420162

# Economic Analysis of Residential Secondary Distribution Systems

H. E. CAMPBELL
MEMBER AIEE

H. E. SINNOTT
ASSOCIATE MEMBER AIEE

WHETHER the industry should go to a higher voltage secondary distribution system to serve the residential-class load has been debated for years. Numerous papers and talks have been presented in recent years on this subject because it is recognized that with the expected load growth a change is "now or never." A recent paper[1] which used some different concepts in distribution produced some results which the authors questioned; consequently, it was decided to analyze this subject using the authors' own techniques and assumptions.

The scope of this paper is confined to a new area with new homes and to a continuation of the use of 120 volts in the home. The demand used in the study is varied from what is expected today for a home with all major appliances to ten times the demand. Such a spread in demand should cover areas of the future with electric heating and cooling. Secondary spans are taken as 140 and 200 feet in order to see the effect of lots with 70- and 100-foot frontages on the economic relations of the various systems.

The secondary systems studied are 120/240-volt and 240/480-volt single-phase, and 240/416-volt and 277/480-volt 3-phase. Area secondary distribution costs as well as the present-day linear-type are studied in order to find the lowest cost system for each voltage and span length at each demand.

A primary voltage of 34.5 kv was used throughout. Only one primary voltage was used to keep the secondary calculations to a minimum. Since the primary voltage of 34.5 kv was used in the previously mentioned paper, the same voltage was chosen for comparison purposes. This selection of primary voltage allows a larger margin of voltage drop in the secondary, in particular where large loads are fed from one distribution transformer, as in the case of area coverage using the 3-phase secondary voltages. This primary voltage tends to favor the higher secondary voltages because of the larger distribution transformers used, with their attendant smaller cost per kva at the larger sizes. It should not be construed, however, that the use of the 3.45-kv primary is advocated for residential areas.

## Description of Residential Area

Professional builders erect about 80% of the new homes today and the vast majority are located in newly developed areas. These are the areas where a change in secondary-system voltage might be considered. The average-size lot today is about 60 by 120 feet, and there is the possibility of the width increasing in the future. Therefore, lots of two sizes are chosen for the study, namely, 70 by 100 feet and 100 by 200 feet, as representative of future conditions. All streets are assumed to be 50 feet wide.

Despite the fact that streets are laid out curved in development planning, a large part of newly developed areas can be considered as a grid pattern. Therefore, for simplicity, this study is made on a grid-pattern basis. It is recognized that where the load is not as uniform as the assumed grid pattern of this study because of cemeteries, parks, etc., the area secondary distribution benefits will diminish. This would be more noticeable at the lighter demands because here the area that can be served from one distribution transformer is the largest.

Each block is assumed to have 24 homes. With the previously mentioned lot dimensions, the blocks used are 200 by 840 feet for the 140-foot-secondary-span case, and 400 by 1,200 feet for the 200-foot-span case. The total number of homes considered in the study is 5,832; this represents an area 9 blocks wide and 27 blocks long. The demand for this group of homes is used to get costs on a dollar per kva basis.

## Description of Systems

All systems in this study are overhead. The following is a description of the secondary systems designed to supply the 5,832 homes:

1. The 120/240-volt system is the one with the conventional voltage for residential areas. This design differs from the conventional design in that the costs of the secondary system are explored for area coverage as well as for linear coverage. Fig. 1(A) shows the usual service entrance to the home.

2. The higher voltage simple-phase system is taken as 240/480 volts. To continue serving homes with 120 volts, the price of an autotransformer is included. The size is taken as 1 kva and 3 kva to see the effect of autotransformer size on the economic comparison. Fig. 1(B) illustrates two types of service entrances which can be used on this system. One is where nothing higher than 240 volts is desired in the home and the other is where 480 volt single-phase is wanted for large loads such as air conditioners and heat pumps. This of course necessitates a new design of high-voltage single-phase motors for 480 volts.

3. One 3-phase system is 240/416-volt 4-wire. The service entrances for 1-phase homes and 3-phase homes are shown in Fig. 1(C). The advantage of this voltage is that standard 230-volt single-phase motors can be used on single-phase services, but it is assumed that the use of standard 440-volt 3-phase motors on the 416-volt services is comparable to the use of 220-volt motors on the 208-volt services.

4. The other 3-phase system studied is 277/480-volt, illustrated in Fig. 1(D). This overcomes the 3-phase motor obstacle of item 3, but it requires that certain appliances such as ranges, water heaters, room air conditioners, etc., be designed for a higher voltage than present-day standards permit.

In all cases, the primary used is 34.5 kv and it is assumed available at the top boundary of the area. Whether the 34.5 kv comes from a step-down substation or a switching station makes no difference in the results of this study.

## Conditions of Study

To make a generalized study of this type, it is necessary to set down certain conditions upon which the study is based. A single set of conditions will not satisfy all situations in practice, and therefore, the conditions have been varied where practical to give breadth to the study.

### Demands

Six average diversified demands per home, from 2.4 kva to 24.0 kva, are investigated and their diversity curves are shown in Fig. 2. The designations put on the curves in Fig. 2 and which are used throughout the paper are the diversified demand per home when it is 1 of 16 in a group of homes. These demands are an extrapolation of information on a "full use" customer.[2] The 2.4-kva curve corresponds to a full-use customer, i.e., one

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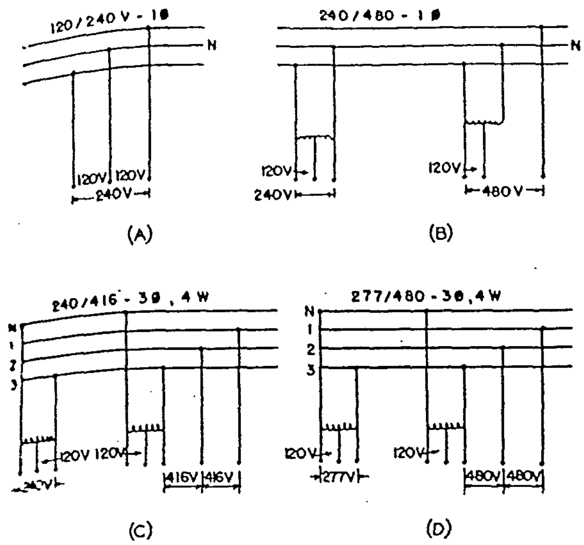
H. E. CAMPBELL and H. E. SINNOTT are with the General Electric Company, Schenectady, N. Y.

Enlargement shown on next page.



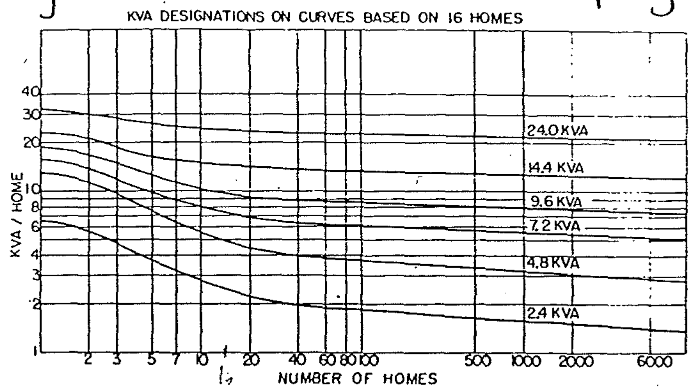




**Fig. 1 (left). Service-entrance facilities**

**Fig. 2 (above). Maximum diversified demand per home versus various numbers of homes**

with all major appliances. The extrapolation is made by assuming that this demand will be doubled by a growth of loads similar in diversity to the type had in the past. This would give the same shape curve for 4.8 kva as for 2.4 kva. For demands greater than 4.8 kva it is assumed that they are caused by addition of other utilization devices, such as air conditioners and heat pumps, which do not have as great a diversity. The curves for 7.2 kva and over were obtained by adding a fixed amount of demand to the 4.8-kva curve.

These curves are used throughout the study to determine line and transformer loading and demands for calculating losses.

### Voltage Regulation

The Edison Electric Institute (EEI) and the National Electrical Manufacturers Association (NEMA) recommend a voltage spread of no greater than 12.5% between the home outlet with the highest voltage and the one with the lowest voltage.[3] Based on this, many utility engineers design the primary, distribution transformer, secondary, and service-drop part of the system for only 10% or 11% spread when the first distribution transformer is one-half loaded and all others fully loaded.

It is assumed that a regulator is in the 34.5-kv primary so that voltage can be held at the first customer's outlet. The allowable voltage spread for the 120/240-volt system is determined as follows:

| Component | Voltage Drop, Per Cent |
|---|---|
| Regular bandwidth | +1.667 |
| Interior wiring, last home | +2.500 |
| Service drop, last home | +0.625 |
| *Interior wiring, first home | −1.250 |
| *Service drop, first home | −0.312 |
| Net drop | +3.230 |

* These are actually voltage rises and are therefore negative voltage drops.

If a limit of 10% voltage drop is arbitrarily set for everything in the system except the primary and the distribution transformers, a figure of 6.77% as the maximum allowable voltage drop in the 120/240-volt secondary is obtained. This leaves 12.5 less 10, or 2.5% voltage drop which includes the voltage drop in the primary and one half of the voltage drop in the last distribution transformer.

The higher secondary voltages require the use of autotransformers. Here the allowable voltage spread is determined as follows:

| Component | Voltage Drop, Per Cent |
|---|---|
| Regulator bandwidth | +1.667 |
| Interior wiring, last home | +2.500 |
| Service wiring, last home | +0.625 |
| Autotransformer, last home | +1.040 |
| *Interior wiring, first home | −1.250 |
| *Service drop, first home | −0.312 |
| *Autotransformer, first home | −0.520 |
| Net drop | +3.750 |

* These are actually voltage rises and are therefore negative voltage drops.

As before, if the limit is 10%, 10 less 3.750 or 6.25% is the maximum allowable voltage drop in the secondary and 2.5% voltage drop for the primary and distribution transformer. Actually, several spot checks were made and it was found that the drop in the primary and the distribution transformer varied between 0.5% and 1.5% so that the various systems fall well within the limit of 12.5% over-all voltage drop.

### Conductors

The primary conductors in sizes no. 3/0 and larger are bare hard-drawn aluminum. For sizes smaller than no. 3/0 the sag becomes excessive for all-aluminum conductors and steel-reinforced aluminum cable is used. The substitution of steel-reinforced aluminum cable is more economical than using additional poles with all-aluminum conductors.

The secondary circuits are bare hard-drawn aluminum and service conductors are covered hard-drawn aluminum.

### Distribution Transformers

Standard kva-rated transformers are used in this study with two exceptions. A 2,000-kva single-phase and a 750-kva 3-phase transformer are included with the standard sizes in order to eliminate the large gap that exists at this point of the preferred ratings.

The maximum permissible load on a transformer is fixed at 120% of the nameplate rating. Diversity in accordance with Fig. 2 is taken into account when determining the load on a transformer.

### Power Factor

A system power factor of 88% is assumed for this study. The motor starting-current power factor is also assumed to be 88%. These may be somewhat low for residential secondary demands as they exist today, but they are believed to be reasonable for future conditions where there will probably be a larger per cent of electronic and motor loads.

### Voltage Flicker

A maximum of 3% voltage change on the 120-volt lamp when a motor starts is assumed satisfactory. This is based on past experience where many utilities have found that designing for such a voltage change is satisfactory.

All systems are designed so that motors complying with the EEI-NEMA rules[4] would not cause more than 3% voltage change. These rules allow 20 amperes for automatically started 115-volt motors and 25 amperes for automatically started

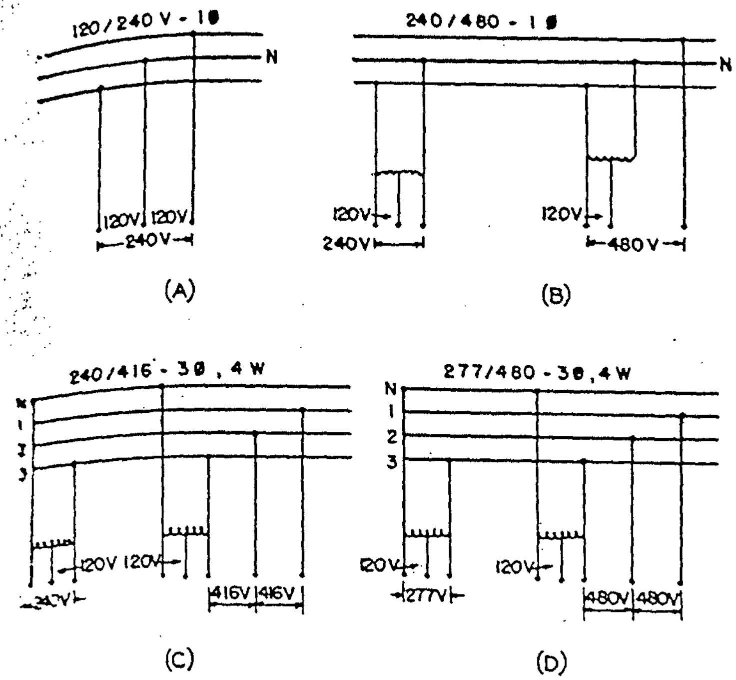
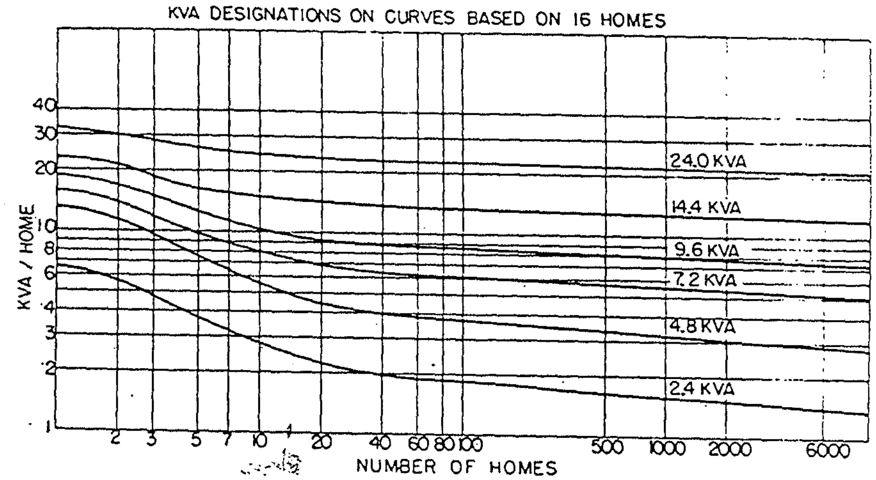



Fig. 1 (left). Service-entrance facilities

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## Power Factor

random phenomenon where generally the restriking occurs at times other than that which would result in the maximum voltage as a result of one restrike. There is evidence, however, to indicate more severe voltage magnitudes occurring on power systems than those included in Table IV.[3–5]

A preliminary investigation describing the effect of lightning arresters on switching surges is described in the *AIEE Transactions*.[6] Further analysis of this phase of the investigation by the Working Group is awaiting the receipt of an industry-wide definition of arrester characteristics under switching surge conditions.

At the present time the Working Group on Switching Surges is devoting its attention to a study of the type of switching surge classified items A.1(d), A.3, and A.4 in the foregoing.

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## Discussion

H. W. Smith and H. M. Ellis (B. C. Engineering Company Ltd., Vancouver, B. C., Canada): The Working Group on Switching Surges has undertaken a very important assignment in that the results of their investigation will provide information required to determine the basic insulation design criteria for high-voltage transmission systems, particularly where lightning surges are not an important factor in arriving at insulation requirements. Knowledge of surges determines the insulation requirements of all equipment on high-voltage systems on a more scientific basis. The establishment of switching surge criteria as a function of the various system characteristics is certainly a very difficult task and the Working Group is to be congratulated on undertaking this assignment.

The other phase of the committee assignment of particular interest to utilities is the system discharge requirement of arresters when switching long cables at transmission voltages. Utilities are installing miles of underground high-voltage cables for transmission of power where right of way for overhead lines is unavailable close to load centers. For these conditions the thermal discharge requirements of the lightning arrester may well exceed even modern station arrester discharge capabilities. It is to be hoped that in the near future the committee will have results to present on this phase of the investigation, including the effect of transformer saturation on arrester thermal duty, on a similar basis to that given for switching long lines in reference 2 of the paper.

I. B. Johnson: The Working Group on Switching Surges wishes to thank, the discussers, H. W. Smith and H. M. Ellis, for their comments on the first report of this group. As indicated in the report, the question of arresters and switching surges has been recognized. Papers on the subject are being solicited and some work has been done. In particular, there is a need for more field data to supplement the results which so far have been obtained and also are now being obtained from studies on systems in miniature.

# Distribution System Load Characteristics and Their Use in Planning and Design


R. H. SARIKAS
ASSOCIATE MEMBER AIEE

H. B. THACKER
MEMBER AIEE


SINCE THE SOLE PURPOSE for the existence of an electric distribution system lies in supplying the requirements of the consumer's utilization devices, it is fundamental that a knowledge of these load requirements is necessary for sound planning of the distribution system and its various components. The economic importance of the knowledge of load characteristics has become more and more recognized with the growth of load on utility systems.

In recent years, much work has been done in this field. Many utilities have made and continue to make, in some form, surveys of the load on their systems.

This paper describes the load survey work being done by one utility company, and how the resultant data is processed and used in distribution planning and design. The paper also demonstrates the importance of a knowledge of load characteristics in the design of equipment which will meet the utility industry's requirements for service with minimum initial investment and operating cost. An example of the need for load information to design equipment having characteristics most desirable to the utility, is the pole-mounted distribution transformer. These transformers represent a major item of capital investment in the utility system and an important segment of operating cost. The optimum design of the distribution transformer, in terms of such things as loss ratio, impedance, and insulation system life, is inherently related to the characteristics of the load to which the transformer will be subjected.

Information obtained from utility-load surveys can be used for many purposes other than distribution system planning and optimum equipment design. Often, data from the same load survey will also be used in studies of rate structure, cost analysis, and development of selective selling programs.

## Classes of Loads

To facilitate the orderly determination of load characteristics, loads may be divided into the following major classes: residential, rural, commercial, and industrial. These classes usually can be further subdivided, based on some peculiarity of the particular class of load being served. Examples are: residential, large

## Method of Conducting Load Surveys

One of the most useful survey methods for determining load characteristics is the method of group-load surveys. Test groups are selected on the basis of homogeneity of character and use, predominance of one class, and convenient layout of distribution lines for test metering. If the test groups are selected as being representative of their class, the load survey data can have a broad application.

### Example of Group Load Survey

The plot plan of a typical residential test group is shown in Fig. 1. The group is one of 48 similar residential test groups in a current load survey. These groups are of varying size in order to provide coincidence information. One-fourth of the groups has less than 6 customers, 1/4 has 6 to 12 customers, 1/4 has 13 to 20 customers, and the remainder has over 20 customers. An indicating, 15-minute interval, kilowatt demand meter is installed at each residence. Graphic integrating meters with 15-minute interval strip charts are installed at the master-meter location on the primary circuit to measure kilowatts and reactive kilovolt-amperes for the entire group. These tests run for a 12-month period. In addition to daily load curves, an analysis of these data furnishes the following:

1. Correlation between the kilowatt-hour (kw-hr) usage of an individual consumer and his peak demand.
2. Coincidence factor relationship.
3. Loss and power-factor data.
4. Load factor information.

The derivation and significance of the above factors and relationships is discussed in the following paragraphs.

### Correlation Between Kw-Hr and Demand

This relationship has been established for the yearly peak demand versus annual kw-hr usage, winter peak demand versus winter kw-hr usage, and summer peak demand versus summer kw-hr usage. These latter relationships are more significant in view of the increasing saturation of residential air conditioning. The annual kw-hr versus demand relationship will not provide reliable estimating results where there is a mixture of air-conditioning and nonair-conditioning customers and where the yearly peak ordinarily occurs during the winter. The inaccuracy of the estimate is due primarily to the inclusion of the air-conditioning kilowatt-hour usage in the annual consumption figures. Estimates of winter peak demands for customers with large air-conditioning usage, based on this relationship, will be higher than actual demand, since the air-conditioning usage contributes greatly to the annual kw-hr consumption and adds nothing to the winter peak demand. The least-squares lines of best fit for the summer and winter peak-period relationships are shown in Figs. 2 and 3. A tabulation of the pertinent statistics underlying these curves is provided in Tables I and II.

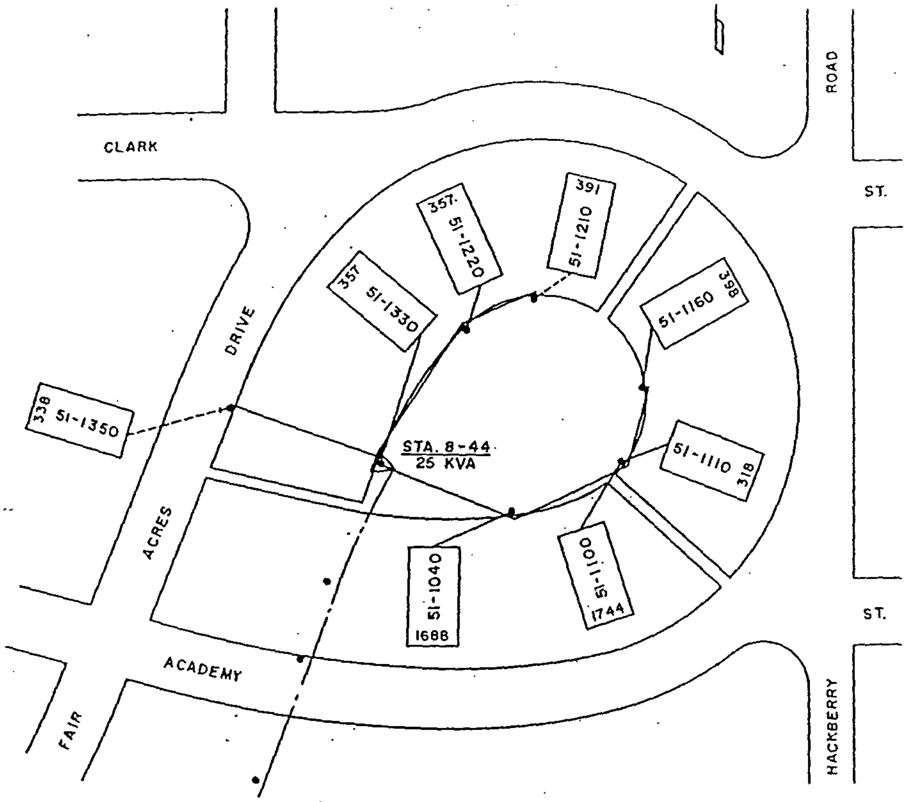


Fig. 1. Residential load survey plot plan

### Intraclass Coincidence Factor

Use of test groups of varying size provides the data needed to evaluate intraclass coincidence. Scatter diagrams of test-group coincidence factors for summer and winter peak periods along with the hyperbolic regression lines are shown in Figs. 4 and 5. The test-group coincidence factors, shown in the figures, are the ratio of the maximum diversified demand of the group during the 4-month peak period, to the sum of the maximum noncoincident demands, for each customer, during the same peak period. These curves are similar to those published by others.[1,2,] The coincidence relationship between various test groups is obtained by comparing the peak demand period graphic chart readings of the test group master meters.[4]

Surveys utilizing a single group size, while desirable for some purposes, do not furnish intragroup coincidence-factor information. However, the kw-hr versus demand relationships discussed previously, can be derived. An example of the results of such a survey, made some years ago, is shown in Fig. 6.

### Interclass Coincidence Factor

If the test locations can, in the aggregate, be considered statistically representative of the residential customers as a whole, a load curve for the entire residential class of customers can be prepared. If this same technique is used for other classes of customers, similar load curves can be prepared. When these lo

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R. H. Sarikas is with the Illinois Power Company, Decatur, Ill., and H. B. Thacker is with Westinghouse Electric Corporation, Pittsburgh, Pa.

group, kw-hr consumption versus demand, summer-peak period

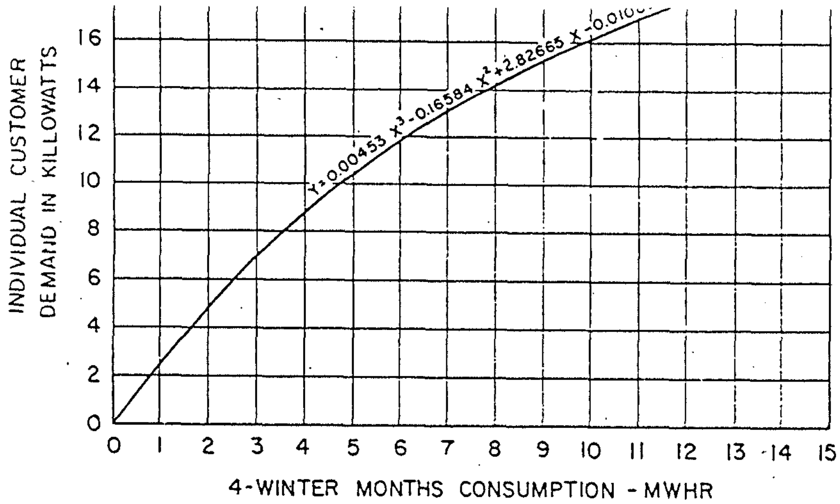


**Fig. 3 (left). Residence test group, kw-hr consumption versus demand, winter-peak period**

curves are combined, the system load curve is obtained. Such a series of load curves along with the actual system send-out from dispatching records is shown in Fig. 7. Comparison of the series provides interclass coincidence relationships.

## Loss Data

Loss data are obtained as a by-product of the load study. For example, in the residential test group shown in Fig. 1, the difference between master-meter kw-hr readings and total sales billed represents

of these data permits an evaluation of the effect of such loads as air conditioning and the improvement possible by such means as series and shunt capacitors. Data relative to the power factor of loads on the secondary system also permit an intelligent decision whether or not to use secondary capacitors after determining a breakeven power factor for secondary versus primary capacitors.[7]

## Load Factor

Load factor can be obtained from an analysis of the daily load curves or the load factor may also be obtained from a comparison of demand and kw-hr readings for a comparable period. The load-factor versus coincidence-factor relationship is also available. This relationship, which has limited application in distribution planning, is useful in developing "selective selling" programs.[8]

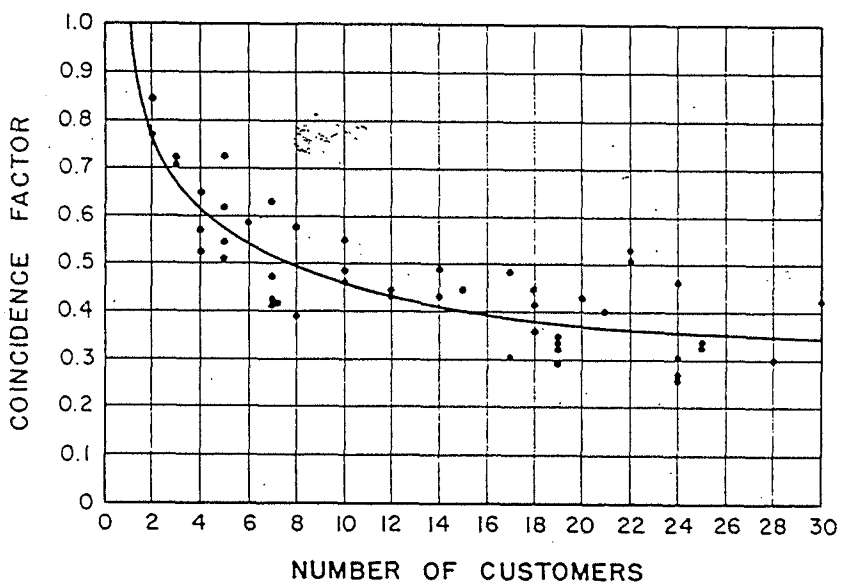


**Fig. 4. Residence test group, coincidence-factor relationship, summer-peak period**

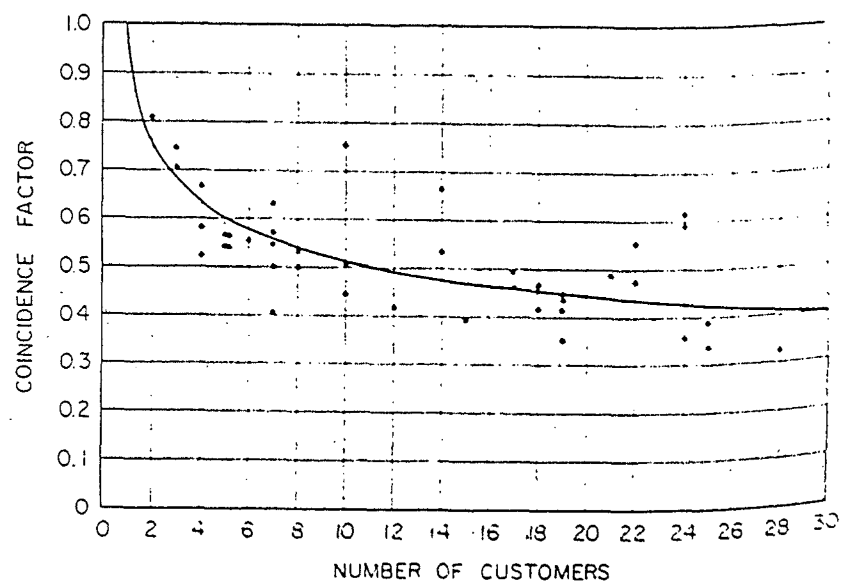


**Fig. 5. Residence test group, coincidence-factor relationship, winter-peak period**

Exhibit ____ (AG-PLC-23)
Adjustment for Load Diversity at the Transformer



| | Class Peak[1] | Sum of Customer Max Demand[2] | Class Coincidence Factor | Customers per Transformer | Transformer Coincidence Factor | Load @ transformer | MECo Transformer Allocator | Diversity-Corrected Allocator |
|---|---|---|---|---|---|---|---|---|
| R-1/2 | 1,161,100 | 3,543,986 | 0.328 | 8 | 0.550 | 1,949,192 | 67.4% | 56.1% |
| R-4 | 7,007 | 14,892 | 0.471 | 2 | 0.861 | 12,825 | 0.3% | 0.4% |
| St. Light | 30,662 | 30,662 | 1.000 | | 1.000 | 30,662 | 0.6% | 0.9% |
| G-1 | 307,880 | 508,737 | 0.605 | 4 | 0.742 | 377,289 | 9.7% | 10.8% |
| G-2 | 378,730 | 509,057 | 0.744 | 1.5 | 0.894 | 455,077 | 9.7% | 13.1% |
| G-3 | 278,964 | 336,202 | 0.830 | 1 | 1.000 | 336,202 | 6.4% | 9.7% |
| G-4 | 251,482 | 316,320 | 0.795 | 1 | 1.000 | 316,320 | 6.0% | 9.1% |
| Total | 2,415,825 | 5,259,856 | | | | 3,477,567 | | |

**Notes:**
[1] Work Paper PTZ-3, p.4.
[2] Exhibit PTZ-3, p.7
Loads at step-down

Exhibit ____ (AG-PLC-24)
Derivation of Secondary Allocator

| | Class Peak[1] | Sum of Customer Max Demand[2] | Class Coincidence Factor | Average Customers per Line | Secondary Coincidence Factor | Load @ secondary | MECo Secondary Allocator | Diversity-Corrected Allocator |
|---|---|---|---|---|---|---|---|---|
| R-1/2 | 1,161,100 | 3,424,141 | 0.339 | 3.00 | 0.559 | 1,915,447 | 76.93% | 68.23% |
| R-4 | 7,007 | 14,389 | 0.487 | 1.5 | 0.829 | 11,928 | 0.32% | 0.42% |
| St. Light | 30,662 | 30,662 | 1.000 | | 1.000 | 30,662 | 0.69% | 1.09% |
| G-1 | 307,880 | 491,533 | 0.626 | 2.5 | 0.776 | 381,341 | 11.04% | 13.58% |
| G-2 | 377,565 | 490,320 | 0.770 | 1.25 | 0.954 | 467,769 | 11.02% | 16.66% |
| G-3 | | | | | | | | |
| G-4 | | | | | | | | |
| Total | 1,884,214 | 4,451,045 | | | | 2,807,148 | 100.0% | |

**Notes:**
[1] Work Paper PTZ-3, P.4
[2] Exhibit PTZ-3, p.7.
Loads at secondary

Exhibit ____ (AG-PLC-25)
Derivation of Allocators for Customer Accounts and Service Expenses



| Customer Accounts Expenses | Total | R-1/R-2, R-4 | R-1 / R-2 | R-4 | G-1 | G-2 | G-3/G4 | St. Light |
|---|---|---|---|---|---|---|---|---|
| 901 Supervision | $1,555,200 | $1,263,631 | $1,261,477 | $2,154 | $235,554 | $45,057 | $10,958 | $0 |
| Accounts 902-904 | 100.00% | 81.25% | 81.11% | 0.14% | 15.15% | 2.90% | 0.70% | 0.00% |
| 902 Meter Reading Expense | $8,758,037 | $7,298,432 | $7,279,086 | $19,346 | $1,060,156 | $311,622 | $87,828 | $0 |
| Meter Time Allocator | 100.00% | 83.33% | 83.11% | 0.22% | 12.10% | 3.56% | 1.00% | 0.00% |
| 903 Customer Records & Collections | $20,243,316 | $16,477,130 | $16,447,947 | $29,183 | $3,023,682 | $595,704 | $146,800 | $0 |
| Accounts 902 and 904 | 100.00% | 81.40% | 81.25% | 0.14% | 14.94% | 2.94% | 0.73% | 0.00% |
| 904 Uncollectibles | $11,775,008 | $9,356,035 | $9,348,095 | $7,940 | $2,092,234 | $274,042 | $52,697 | $0 |
| Uncollectible Revenues | 100.00% | 79.46% | 79.39% | 0.07% | 17.77% | 2.33% | 0.45% | 0.00% |
| 905 Misc. Customer Account Expense | $17,336 | $14,086 | $14,062 | $24 | $2,626 | $502 | $122 | $0 |
| Accounts 902-904 | 100.00% | 81.25% | 81.11% | 0.14% | 15.15% | 2.90% | 0.70% | 0.00% |
| Total Customer Accounts Expense | $42,348,897 | $34,409,313 | $34,350,666 | $58,647 | $6,414,251 | $1,226,927 | $298,405 | $0 |

Exhibit ____ (AG-PLC-25)
Derivation of Allocators for Customer Accounts and Service Expenses



| Customer Accounts Expenses | Total | R-1/R-2, R-4 | R-1 / R-2 | R-4 | G-1 | G-2 | G-3/G4 | St. Light |
|---|---|---|---|---|---|---|---|---|

| Customer Service & Information Expense | Total | R-1/R-2, R-4 | R-1 / R-2 | R-4 | G-1 | G-2 | G-3/G4 | St. Light |
|---|---|---|---|---|---|---|---|---|
| 907 Supervision | $816,730 | $520,340 | $518,857 | $1,483 | $71,443 | $60,738 | $161,378 | $2,913 |
| Average of Energy and Customers | 100.01% | 63.71% | 63.53% | 0.18% | 8.75% | 7.44% | 19.76% | 0.36% |
| 908 Power Quality Assessment Program | $567,729 | $9,538 | $6,359 | $3,179 | $130,748 | $121,210 | $299,818 | $0 |
| Participation | 46.06% | 1.68% | 1.12% | 0.56% | 23.03% | 21.35% | 52.81% | |
| 908 Other Customer Assistance Expense | $608,344 | $387,577 | $386,472 | $1,105 | $53,215 | $45,241 | $120,203 | $2,170 |
| Average of Energy and Customers | 100.01% | 63.71% | 63.53% | 0.18% | 8.75% | 7.44% | 19.76% | 0.36% |
| 909 Information & Instruction Expense | $2,789,001 | $1,776,877 | $1,771,812 | $5,066 | $243,967 | $207,409 | $551,079 | $9,947 |
| Average of Energy and Customers | 100.01% | 63.71% | 63.53% | 0.18% | 8.75% | 7.44% | 19.76% | 0.36% |
| 910 Misc. Customer Service Expense | $1,416,903 | $902,711 | $900,138 | $2,573 | $123,943 | $105,371 | $279,966 | $5,054 |
| Average of Energy and Customers | 100.01% | 63.71% | 63.53% | 0.18% | 8.75% | 7.44% | 19.76% | 0.36% |
| Total Customer Service & Info. Expense | $6,198,707 | $3,597,043 | $3,583,637 | $13,407 | $623,316 | $539,968 | $1,412,444 | $20,083 |
| **Total Customer O&M** | $48,547,604 | $38,006,356 | $37,934,303 | $72,053 | $7,037,567 | $1,766,896 | $1,710,849 | $20,083 |
| Allocator | 99.99% | 78.29% | 78.14% | 0.15% | 14.50% | 3.64% | 3.52% | 0.04% |

| Derivation of the Allocators Used Above | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Accounts 902-904 | $40,776,361 | $33,131,596 | $33,075,127 | $56,469 | $6,176,072 | $1,181,368 | $287,325 | $0 |
| | 100.00% | 81.25% | 81.11% | 0.14% | 15.15% | 2.90% | 0.70% | 0.00% |
| Energy with losses | 100.00% | 37.90% | 37.62% | 0.28% | 8.50% | 13.69% | 39.29% | 0.61% |
| Number of Customers | 100.02% | 89.52% | 89.44% | 0.08% | 8.99% | 1.18% | 0.23% | 0.10% |

Source:
From Exhibit PTZ-1, except as noted in table and text.

Exhibit ____ (AG-PLC-26)
Derivation of the Allocator for "Customer Related" Distribution O&M

Exhibit ____ (AG-PLC-26)

| | Total | R-1/R-2, R-4 | R-1 / R-2 | R-4 | G-1 | G-2 | G-3/G4 | Street Light |
|---|---|---|---|---|---|---|---|---|
| Customer / St. Light Specific: | | | | | | | | |
| 369 Services | $72,195,267 | $63,549,581 | $63,485,934 | $63,647 | $6,063,338 | $2,234,789 | $347,559 | $0 |
| 370 Meters | $63,984,379 | $32,937,273 | $32,820,965 | $116,308 | $14,951,059 | $9,496,696 | $6,599,350 | $0 |
| 373 St. Lighting & Signal | $72,497,972 | $0 | $0 | $0 | $0 | $0 | $0 | $72,497,972 |
| Total | $208,677,618 | $ 96,486,854 | $ 96,306,899 | $179,955 | $ 21,014,397 | $ 11,731,486 | $ 6,946,909 | $ 72,497,972 |
| Allocator | 100.00% | 46.24% | 46.15% | 0.09% | 10.07% | 5.62% | 3.33% | 34.74% |

*Source: From PTZ-2, except for changes explained in the text.*

Exhibit ____ (AG-PLC-27)
Summary of Additional Allocators

Exhibit ____ (AG-PLC-27)

| Allocator | Residential R-1 / R-2 | Residential R-4 | Residential Total | Small General Service G-1 | Small General Service G-2 | Small General Service Total | G-3/G-4 | Light |
|---|---|---|---|---|---|---|---|---|
| [1] Coincident Peak Demand w/ losses | 34.66% | 0.17% | 34.83% | 12.04% | 16.82% | 28.86% | 36.31% | 0.00% |
| [2] 12-month CP average w/losses | 38.26% | 0.27% | 38.53% | 9.90% | 14.59% | 24.50% | 36.35% | 0.62% |
| [3] Class Peak Demand w/losses | 40.39% | 0.24% | 40.64% | 10.71% | 13.48% | 24.19% | 34.11% | 1.07% |
| [4] Energy with losses | 37.62% | 0.28% | 37.90% | 8.50% | 13.69% | 22.20% | 39.29% | 0.61% |
| [5] Excess Capitalized Expenditure | 0.00% | 0.00% | 0.00% | 8.45% | 13.61% | 22.07% | 77.93% | 0.00% |
| [6] Excess Capacity | 0.00% | 0.00% | 0.00% | 11.88% | 16.60% | 28.48% | 71.52% | 0.00% |
| [7] Diversified Demand @Transformer | 56.05% | 0.37% | 56.42% | 10.85% | 13.09% | 23.94% | 18.76% | 0.88% |
| [8] Diversified Demand @Secondary | 68.23% | 0.42% | 68.66% | 13.58% | 16.66% | 30.25% | n.a | 1.09% |
| [9] Customer Accounts Allocator | 78.14% | 0.15% | 78.29% | 14.50% | 3.64% | 18.14% | 3.52% | 0.04% |
| [10] Customer Related Distribution O&M | 46.15% | 0.09% | 46.24% | 10.07% | 5.62% | 15.69% | 3.33% | 34.74% |

**Sources:**
Allocators for Allocated Cost of Service Study Exhibit. Exhibit PTZ-1, page 17 of 18.
file S:\RADATA\95MACSE\ALLOCOSS.WK4
[1] From Exhibit 6(f) section 2, calculation of losses. and Workpaper PTZ-2 page 4 of 10, and Workpaper PTZ-2, page 4 of 10.
[2] From Exhibit 6(f) section 2.
[3] From Exhibit 6(f) section 6, Develpment of Demands Coincident with Class Peak. The figure for lighting was replaced by that reported in sum of customer maximum demand at primary.
[4] From Exhibit PTZ-11, PTZ-7(page 25 of 26), and PTZ-6 (page 4 of 11).
[5] See Exhibit 2: Derivation of allocator for excess capitalized energy.
[6] See Exhibit 2: Derivation of allocator for excess capacity.

AG PLC 15
AG PLC 14