THE AVOIDED COSTS ASSOCIATED WITH COGENERATION:
A CASE STUDY OF CON ED

MASTER

R. BRIGHT, H. DAVITIAN, AND J. MARTORELLA

AUGUST 1980

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DEPARTMENT OF ENERGY AND ENVIRONMENT

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By

R. Bright
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PREFACE

Since 1978, the National Center for Analysis of Energy Systems has had a program of studies investigating the potential impacts that decentralized, utility-interconnected energy production technologies might have on electric utilities. The program has combined the development of analytical methods with the application of these methods to specific studies. The focus of the program has been the long-run costs imposed on utilities when they provide supplementary power to facilities with interconnected devices and the long-run savings the utility experiences when power from decentralized technologies is delivered to the grid. The technologies include cogeneration, solar heating and hot water systems (with electric backup), photovoltaic systems, wind, etc.

This report describes the application of the Brookhaven method of computing avoided costs to an analysis of the effects that cogeneration in commercial buildings in New York City is likely to have on the Consolidated Edison Company.

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The authors appreciate the tireless contributions of Ms. Lili Li who performed the computations for the facility economic analysis and the rate comparisons and Mr. Timothy Sills who developed several of the computer codes used in this project.

SUMMARY OF PRINCIPAL FINDINGS

The potential impact of cogeneration in office and apartment buildings in New York City on the Consolidated Edison Company (Con Ed) has been investigated using a method of utility cost and fuel use analysis developed at Brookhaven National Laboratory. This method computes a utility's long run marginal costs and long run marginal fuel consumption associated with load modifications due to the introduction of on-site energy producing technologies. The principal findings of this study are summarized below:

1. Con Ed's long run average cost is more likely to go down than up due to cogeneration in office and apartment buildings. If Con Ed's annual generation is reduced by 5% by the year 2000 due to office cogenerators, then it would experience a 2-3% drop in its average cost. A similar load reduction due to apartment building cogeneration leads to a 0.3% decrease in average cost if the cogenerators are not connected to the grid and a 0.4% increase if they are connected.

2. The utility's avoided costs (i.e., its long run marginal savings) associated with the gross power output of the cogeneration systems are 10.5 ¢/kWh for the office building and 6.4 ¢/kWh for the apartment building. (These are the utility's savings for each kilowatt-hour of private generation during the period of the mid-1980's). For the office building, the marginal savings are higher than the utility's long run average cost (9.1 ¢/kWh) and about equal to its long run marginal cost of growth. For the apartment building it is lower than both of these parameters. The relationships among the marginal costs and savings show little variation over the 20 year study period nor are they very sensitive to changes in market penetration.

3. The utility's marginal savings include a component for avoided capacity costs. During the 1980's these avoided capacity costs are associated with the transmission and distribution system investments not incurred if Con Ed's loads are reduced due to cogeneration. In the 1990's when the schedule of generation capacity additions can be modified, the avoided capacity costs become larger. Even during the 1980's, there are sizable avoided capacity costs ranging from about 1¢/kWh for apartment building cogeneration to about 3¢/kWh for office building cogeneration. Although the production cost and capacity cost components of the total avoided cost change considerably during the 1990's, their sum stays relatively constant in real terms.

4. There are net savings in the use of oil due to cogeneration (assuming the building used oil for its boilers before it switched and diesel fuel in its cogenerators afterwards). During most of the 1980's the annual savings are about 1/2 million gallons per year per building for office cogeneration and about 1.2 million gallons per year for apartment cogeneration. Although the savings decline and become a net increase in oil use by the end of the century, the cumulative oil savings are still positive throughout the next two decades for a building converting to cogeneration now and continuing to cogenerate to the year 2000.

1 INTRODUCTION

Recent changes in federal law regarding the regulatory treatment of privately generated electricity have sharply lowered the economic and regulatory barriers to private power production. The Public Utility Regulatory Policies Act of 1978 (PURPA) required electric utilities to purchase power from qualifying cogenerators and small power producers and to sell supplementary and backup power to them. In February of 1980, the Federal Energy Regulatory Commission (FERC) announced rules to guide state public utility commissions in setting rates for the interchange of power between private power producers and utilities.¹ The rules require that utilities pay qualifying cogenerators and small power producers an amount equal to the full costs the utility avoids (including avoided expenditures for capacity) as a consequence of the private generation. In essence, this requires that rates for the "buy-back" of privately generated power be based on marginal costs. The rules permit arbitrage by a private generator; i.e., the purchasing of electricity at conventional rates while simultaneously selling at marginal cost based rates. When a utility's marginal costs are higher than its average costs, arbitrage can significantly benefit the private generator.

The combination of these regulatory changes and the rapid rise in fuel prices during the 1970's has created a climate that is much more favorable for private generation than that which had previously existed. However, since both PURPA and the FERC rules allow the state public utility commissions substantial discretion in the manner in which the standards and rules are to be implemented, their ultimate consequences are not yet clear. By March 1981, the state commissions must have set interim rates for private producers. This requires not only judging the appropriateness of the rates themselves but, more importantly, selecting acceptable methods of computing rates.

The purpose of this study is to demonstrate one method of computing rates for privately produced power. In addition, it shows how the long run impacts of private generation on a utility's costs, capacity requirements, and fuel consumption can be analyzed. The method of analysis was developed at Brookhaven National Laboratory and is suitable for examining the potential effects on utilities of decentralized, privately owned grid-connected energy technologies including those having a variable generation pattern (e.g., solar, wind, and cogenerating systems).²

The introduction of cogeneration systems into the service area of the Consolidated Edison Company of New York (Con Ed) was selected as a suitable case for study. Con Ed supplies electricity, gas and steam to customers in the New York metropolitan area. Its service territory is composed of the City of New York and most of the County of Westchester. Interest in private generation is particularly strong in New York City because Con Ed's electric rates are among the highest in the country. This interest is focused on cogenerating devices--electric power plants with reject heat recovery equipment--which can be used in commercial and apartment buildings and in industrial facilities.* This study was limited

*The conditions under which oil- and gas-consuming cogeneration systems can qualify for the benefits provided by PURPA and the FERC rules are currently being determined by the Economic Regulatory Administration (ERA). The indications are that the ERA will permit the types of cogeneration systems analyzed in this study to so qualify.

to an examination of cogeneration in apartment and office buildings.

The energy efficiency of a cogeneration system is substantially higher than the overall efficiency achieved with the separate production of electricity and heat. Because of this high efficiency, cogenerating systems have lower operating costs than the combined operating costs of separate generating equipment, provided the same fuel was used in both cases.* Although the economics of conventional power production have favored utility ownership and operation of large, central-station plants, this is not necessarily true for cogeneration. Since it is costly to transport thermal energy, it is usually advantageous to locate the cogenerating system very close to the point at which the heat will be used. Furthermore, the cost per kilowatt of capacity of a small, compact, yet highly efficient cogenerating device is only about half that of baseload coal or nuclear power plants. Consequently, on-site, privately owned cogenerating systems may experience an early and rapid market penetration.†

The study was conducted in cooperation with the staff of the New York State Public Service Commission. The New York Commission is currently conducting a generic on-site generation rate case for Con Ed. This case is serving the double purpose of determining rates for Con Ed and also defining the Commission's general policy regarding rate design for private generation. The policies adopted by the New York Commission are expected to have a significant impact on the policies of commissions in other states. Portions of the staff's testimony in this rate case, especially in regard to the long term impacts of cogeneration on Con Ed relied extensively on the results of this study.

In the four chapters that follow, the specific assumptions and procedures employed in applying the method to an examination of the effects of cogeneration on Con Ed, are described. Following this, the results of the analysis are presented.

2 OVERVIEW OF THE ANALYTICAL METHOD

The method of analysis used in this study can be used to compute either time-differentiated or class-differentiated long-run marginal costs and long-run marginal fuel requirements. To compute time-differentiated costs and fuel requirements, the utility's load pattern is changed by a fixed increment over a daily, weekly and seasonally defined rating period. The changes in the utility's long-run costs and long-run fuel requirements are then computed. To compute class-differentiated marginal costs and fuel requirements,

*If the utility burns a fuel cheaper than the fuel used in the cogeneration system, the operating costs of the latter are not necessarily lower. However, Con Ed's marginal fuel consumption will be almost entirely oil at least through the end of this decade. (See chapter 7).

†Although small, privately-owned cogeneration systems are the focus of this study, it should be mentioned that Con Ed itself is a major cogenerator, selling steam which is produced jointly with electricity in some of its power plants.

the utility's load pattern is modified instead by the load or generation pattern of a particular class of customers. The resulting costs and fuel requirements are specific to that class. In this study, class-differentiated marginal costs and marginal fuel requirements were computed for two types of potential cogenerators.

The analytical approach consists of first determining the detailed daily, weekly, and seasonal pattern of the load modifications that would result from the use of cogeneration through the use of a facility simulation model. The overall effect of the use of cogeneration on the utility's loads are estimated by combining these load modifications with various projections of the market penetration of cogeneration. A capacity expansion model is then used to compute the utility's future stream of capacity and production costs both with and without the use of cogeneration. From these two streams of future costs, the utility's marginal costs and the changes in its fuel requirements can be computed.

Figure 1 schematizes the overall conception of the analytical method. A more detailed picture of the information requirements and procedures used in the analysis is given in Figure 2. A step-by-step outline of the method is provided in Chart 1. The method is described in detail in a separate report.²

3 FACILITY SIMULATION

3.1 The DOE-2 Model

Although it would be desirable to use operating data from actual cogeneration systems in determining the effect of cogeneration on utility loads, these are rarely available today. As a substitute, we employed a modified version of a model, DOE-2, which can simulate the performance of a cogeneration system in a building.³ Given input data regarding the building's structure, its HVAC system (including the cogeneration device, if any), its occupancy and appliance use schedule, and weather data, the DOE-2 model determines its hourly heating and electric loads. It then schedules the operation of the boilers and cogeneration devices to meet these loads. The model's primary output consists of an hourly tabulation of the building's electrical and thermal loads and the hourly consumption of boiler and diesel fuel and purchased electricity required to meet those loads. For a cogeneration system that is intertied to the utility, the hourly interchanges of electricity with the utility are also provided. Monthly and annual summaries of these parameters are tabulated.

The model is easy to use, inexpensive to run, and permits the rapid investigation of the fuel use and costs (at the facility) of various cogeneration system options.

3.2 Building Characteristics

The characteristics of the buildings modeled were derived from actual buildings constructed in the last decade. The office building is a 31-story glass and steel tower typical of modern office building architecture. The design was that of a building constructed in Chicago in

Figure 1. Simplified outline of method.

FIGURE 2. DETAILED SCHEMATIC OF THE METHOD

Chart 1

OUTLINE OF THE METHOD OF ANALYSIS

- (1) Identify pattern of electrical generation and/or load of new technology; i.e., hourly load pattern for entire year.
 - a. E.g., i) for residential solar hot water system, identify the pattern of backup electricity requirement; ii) for cogeneration, identify the pattern of electricity generation.
 - b. Where available, actual data from real systems can be used. Otherwise, simulation models are available for estimating the performance of many new technologies.
- (2) Compute future annual or seasonal revenue requirements for utility assuming new technology is not introduced (base case).
 - a. Use capacity expansion model with embedded production costing routine.
 - b. Assume established load forecasts, capacity options, and costs.
- (3) Modify load forecast assuming new technology is introduced.
 - a. Assume one or more market penetration projections.
- (4) Compute future annual revenue requirements with modified load.
 - a. Reoptimization of capacity expansion schedule.
- (5) The change in revenue requirements from the base case to the modified case is the incremental cost (value) to the utility of the incremental load (generation) due to the introduction of the new technology.
 - a. The capacity cost and production cost components of the change in revenue requirements can be separately identified.

1974. The apartment building is a twin tower, brick and concrete block structure, typical of large apartment buildings built in the last two decades. The actual building is located in the New York metropolitan area and has just recently been completed.

A summary of the characteristics of the two buildings is provided in Chart 2. To illustrate the type of information needed by the simulation model, a detailed specification of the characteristics of the office building structure, its heating, ventilating and air conditioning, (HVAC) system, and its assumed occupancy and appliance use schedule as used in the simulation analysis are provided in Appendix A.

The characteristics of the heating and electrical equipment for the two buildings are shown in Chart 3.* The electrical system without cogeneration is simply the conventional utility electric service. The combinations of the absorption and centrifugal chillers shown in the chart are the optimal combinations for each building based on an analysis of facility economics (see Section 3.5). Although most existing buildings will have a much lower fraction of absorption chillers, the cost of adding absorption chillers would be a small increment to the total cost of adding a cogeneration system.†

Only one kind of structure was modeled for each building type. Nevertheless, the generation/load patterns computed are representative of the patterns for a broad cross-section of buildings within each type. This is because the impact of cogeneration on a utility is primarily determined by the relationships between the temporal pattern of the device's output and the temporal patterns of the utility's load. Since the generating pattern of the cogeneration system is almost entirely determined by the occupancy and appliance use schedule, and not by the structure, the impact on the utility will vary little with the kind of structure.

3.3 Cogeneration System Characteristics and Operation

The optimal cogeneration system for both buildings (based on the economic analysis described Section 3.5) consists of five diesel cogeneration sets with a total capacity of 4.4 MW in the apartment and 4.3 MW in the office building. Several manufacturers currently market units that are suitable for these applications.

The operating strategy for the cogeneration system is shown in Figure 3. Three operating states are possible: 1) thermal loads greater than electrical loads; 2) electrical loads greater than thermal loads; 3) low electrical and thermal loads. In the third case, the operation of

*The boiler capacity required, both with and without the cogeneration unit, is given in Chart 3. Since it is assumed that the cogeneration system is installed as a retrofit, no credit is taken in the facility economic analysis for the unused boilers that are no longer needed.

†Trane, a manufacturer of chillers, quotes figures of about \$11,000 per 100 tons of chiller capacity. This figure with a 40% installation markup leads to the 5 to 10% estimate.

Chart 2

BUILDING STRUCTURE CHARACTERISTICS

Apartment

Size	960,088 ft ²
Shape	2 towers Towers: 10 stories 490 (l) x 100 (w) x 100 (h) ft
Walls	4 in. hollow concrete block - air space - 4 in. brick veneer
Roof	Concrete slab covered by gravel, 1 in. rigid insulation
Windows	Double glazed
Apartments	Mixture of four sizes (ft ²): 1034, 1421, 1700, and 2361
HVAC	Four pipe fan coil system for apartments Single-zone reheat for public areas

Office

Size	640,000 ft ²
Shape	1 tower, 31 stories 200 (l) x 100 (w) x 400 (h) ft
Frame	Steel frame with concrete floors
Walls	Insulated curtain wall Spandrell glass 6 1/2 ft high, 1 in. rigid insulation covering 50% of exterior wall
Windows	Double-glazed grey sheet glass, 6 1/2 ft high, covering 50% of exterior wall
HVAC	Reheat variable volume perimeter system and single zone ceiling induction interior

Chart 3

HEATING AND ELECTRICAL PLANT SPECIFICATIONS

Apartment

Boiler	Four 26×10^6 Btu/hr oil burning units (without cogenerator) Three 35×10^6 Btu/hr units (with cogenerator)*
Absorption Chiller	20×10^6 Btu/hr (1667 tons)
Centrifugal Chiller	5×10^6 Btu/hr (417 tons)
Cooling Towers	Six 32×10^6 -Btu/hr units
Cogeneration System	5 diesel cogenerator sets 4.4-MW total electrical capacity Heat recovery from exhaust, jacket, and lubricating oil

Office

Boiler	Two 18×10^6 -Btu/hr oil-burning units (without cogenerator) One 5×10^6 -Btu/hr oil-burning unit (with cogenerator)*
Absorption Chiller	10.5×10^6 Btu/hr (875 tons)
Centrifugal Chiller	11×10^6 Btu/hr (917 tons)
Cooling Towers	Six 32×10^6 Btu/hr units
Cogeneration System	5 diesel cogenerator sets 4.25-MW total electrical capacity Heat recovery from exhaust, jacket, and lubricating oil

*Boiler capacity needed with cogenerator system. Note that cost analysis assumes a retrofit application and does not apply a credit for the decrease in boiler capacity.

1. Load Condition: Thermal load greater than electrical load

Operating Strategy: Run cogenerator to meet thermal load
Sell excess electricity to utility
Run boilers to meet thermal loads in excess of cogenerator capacity.

2. Load Condition: Electrical loads greater than thermal loads

Operating Strategy: Run cogenerator to meet electrical loads

3. Load Condition: Low electric and thermal loads (i.e., sufficiently low that even one cogeneration unit would be operating at a low part load fraction)

Operating Strategy: Shut off cogenerator
Run boilers to meet thermal loads
Buy electricity from utility

Fig. 3. Operating strategy for operating cogenerator under various load conditions

even one of the diesel cogenerator sets is not cost effective; the part load efficiency would be so low that the operating costs would be unreasonably high. In either of the other two cases, the device is operated so as to meet the higher of the thermal or electrical loads at the facility. Excess electricity in the first case is sold to the utility. Excess heat in the second case is simply wasted. (The latter is a costly mode of operation but, depending on the rate structure for utility electricity, it can still be cheaper for the facility owner to operate the system as a power generator -- i.e., above the point where thermal loads are being fully utilized -- and waste thermal energy than to purchase electricity from the utility.)

3.4 Facility Generation and Load Characteristics

The annual thermal and electrical load patterns for the two buildings as simulated by DOE-2 are shown in Figures 4A and B and the annual average daily patterns are shown in Figures 5A and B. The electrical loads for the two buildings are roughly comparable but the apartment building has much higher thermal loads than the office building. This, of course, is due to the apartment's much larger space heating and hot water demands (the latter being virtually nonexistent in the office building). The office building has a strong peak in its thermal loads in the summer resulting from the thermal demands of the absorption chillers. The apartment building's thermal loads are "double humped" with both a summer and a winter peak. Electrical loads for both buildings peak in the summer.

A utility-connected cogeneration device in the office building meets almost all the thermal and electrical loads of the building. During the summer peak load period, the auxiliary boilers must be operated to meet the peak absorption chiller loads. During this same period, excess electricity is sold to the utility, primarily during the daytime. The office building purchases little electricity from the utility; most of the purchases are at night when loads are too low to run the cogeneration system.

Because of the large disparity between the thermal and electrical loads of the apartment, the optimal cogeneration design for this building produces twice as much electrical energy as needed and meets only half the thermal loads. The excess electricity is sold back to the utility and the deficit in thermal requirements is met by the auxiliary boilers. During the summer peak period, the apartment building sells electricity to the utility. The apartment building purchases no electricity from the utility.

A summary of the facility generation and load characteristics is provided in Table 1.

3.5 Economics of Cogeneration to Facility Owner

Cogenerators with a utility intertie have a certain degree of flexibility in selecting the capacity of their cogenerating devices. Whereas reliability plays a major role in determining the capacity required by an independent cogenerator, the interconnected cogenerator, relying on the utility for back-up, is free to select the device size which will provide the greatest economic return. To be sure that the cogenerating system selected for modeling was a reasonable choice from the perspective of the

FIGURE A

FIGURE B

Figures 4A & B. Monthly patterns of loads and cogeneration for the apartment (A) and the Office building (B).

FIGURE A

FIGURE B

Figures 5A & B. Annual average of the daily load pattern for the apartment (A) and office (B) buildings.

Table 1

SUMMARY OF FACILITY GENERATION AND LOAD CHARACTERISTICS

	<u>Apartment</u>	<u>Office</u>
Electrical Load*		
Annual (GWh/year)	15.8	9.5
Peak (MW)	3.7	4.1
Month of Peak	August	August
Thermal Load		
Annual (10^9 Btu)	228.0	25.6
Peak (10^6 Btu/Hr)	92.0	45.0
Month of Peak	December	July
Ratio of Annual Electrical to Thermal Load	.24	1.4
Optimal Cogen. Capacity (MW)	4.4	4.3
Electrical Generation (GWh/year)	35.1	11.0
Thermal Output Utilized (10^9 Btu/year)	135.1	22.8
Ratio of Electric Sales to Generation	.55	.08
Ratio of Electric Purchases to Generation	0	.04
Fraction of Thermal Load Met by Cogen.	.59	.89

*Note that the electric load changes when cogeneration is added. (See Appendix B.)

facility owner, the following analysis of the economics of cogeneration was conducted.

The discounted rate of return (DRR) and the net present value (NPV) of the investment in cogeneration were computed for a variety of cogeneration system sizes. Both computations were on a pre-tax basis and assumed a 10 year device life, a total installed system cost of \$600 per kilowatt, and diesel oil costs escalating at 3% (real) per year from 1980 levels. The NPV computation assumed a 10% (real) discount rate.

Since rates for the purchase and sale of electricity by the cogenerator have yet to be established, the annual payments and receipts were computed for several proposed rate structures. The rate structures that were analyzed are listed in Chart 4. (The rates are detailed in Appendix C and they are further discussed in Section 8.4.) Using the hourly electrical load and generation data for each facility type and the tariff structures, the cogenerator's annual payments and receipts were calculated. Combining these quantities with the cost of the investment and the cost of diesel fuel, the DRR's and the NPV's were computed. The results are shown in Figures 6 and 7.

The rate structure has a strong effect on the economics of cogeneration to the facility owner; depending on which rates are used, the DRR for the most cost effective system varies from 30 to 50% per year for the apartment and 6 to 19% per year for the office building. The PSC staff's proposed rates provide a greater return than Con Ed's proposed rates. Particularly striking is the sharp reduction in the DRR in going from the existing SC-9 rates (office) to those proposed by Con Ed.

Although the choice of rate structure has a strong effect on the economics of a given cogeneration system to the facility owner, it has virtually no effect on the choice of the optimal cogeneration system. A system sized to meet slightly more than the peak electrical load in each building would provide the best return irrespective of which of these rate combinations was in effect. For the facility modeling, the choice of the optimal system for each building was clear and unambiguous.

This analysis of the economics to the facility owner is limited since it does not account for cash flow, tax, and financing considerations. Nevertheless, given the rate structures studied, it appears that apartment building cogeneration is a sufficiently attractive investment that some market penetration can be anticipated. Office building cogeneration appears less attractive and its use probably would depend strongly on the rate structure actually chosen by the Commission and the specifics of the financial posture of the particular facility.

4 MARKET PENETRATION PROJECTIONS

There are over a thousand office buildings in New York City and over 2000 large apartment buildings. During peak periods, these customers account for nearly 40% of Con Ed's 8000 MW of demand. About 950 of these customers, accounting for a combined peak load of 2300 MW, have individual peak loads in excess of 900 kW, making them hypothetical candidates for cogeneration. Because these two building types alone account for such a large portion of Con Ed's total load, the conversion of even a relatively small fraction of them to cogeneration could have a significant impact on Con Ed.

Figures 6A & B. Discounted rate of return (A) and net present value (B) for the apartment of investment in cogeneration plotted as a function of the ratio of the cogeneration device capacity to the building's peak electric load.

FIGURE A

FIGURE B

Figures 7A & B. Discounted rate of return (A) and net present value of investment in cogeneration (B) for the office building plotted as a function of the ratio of the cogeneration device capacity to the building's electric load.

CHART 4

RATE STRUCTURES ANALYZED

Abbreviation	Purchase	Sale
- - - Apartment - - -		
PSC	PSC staff proposed combined SC-8 and 9 rate structure for purchases	PSC staff proposed buy-back rate
SC-8/C.E.	Existing SC-8 rates	Con Ed proposed buy-back rate
- - - Office - - -		
PSC	PSC staff proposed combined SC-8 and 9 rate structure for purchases	PSC staff proposed buy-back rate
SC-9/C.E.	Existing SC-9 rates	Con Ed proposed buy-back rate
SC-9 C.E./C.E.	Con Ed proposed rate for SC-9 class	Con Ed proposed buy-back rate

Not all of these office and apartment buildings are likely candidates for conversion to cogeneration, however. To make effective use of cogeneration, a facility must have large thermal loads. For an independent cogenerator (i.e., no utility intertie), a further constraint is that the electrical and thermal loads be roughly coincident in time. This is not necessary for an interconnected cogenerator; however, in this case it is economically advantageous if the thermal loads coincide with the utility's peak load periods. For an office or apartment building, these considerations imply that the building should have a central air conditioning system consisting at least in part of absorption chiller units if it is to be considered a realistic candidate for cogeneration. Absorption chillers are driven by thermal energy (in contrast to centrifugal chillers, driven by mechanical energy supplied by electricity or steam) which can be supplied by the thermal output of the cogeneration system. Without absorption chillers, the thermal loads of these buildings are generally too small most of the year to justify the investment in cogeneration. Since central air conditioning cannot be added to a building not already having it without incurring an unreasonably high cost, the building must have a central air conditioning system to be a realistic candidate for cogeneration. However, it need not already have absorption chillers since these can be added at the time the cogeneration system is installed at a modest extra expense; an added investment of some 5 to 10% over the cost of the cogeneration system would pay for the needed chillers.

A 1977 survey conducted by Syska and Hennessy and the Tishman Research Corporation⁴, indicated that about 60% of the office buildings surveyed in New York

have central air conditioning systems, 16% of which use absorption chillers. This study identified 69 buildings using absorption chillers. Assuming the 436 building surveyed to be a representative sample of the total office building stock of 1030 buildings, then about 160 office buildings in the city can be assumed to be prime candidates for cogeneration on the basis of the suitability of their existing HVAC equipment. Another 600 office buildings using centrifugal chillers constitute a slightly less favorable market for cogeneration; again this figure is based only on their HVAC equipment.

Since central air conditioning systems are not generally used in apartment buildings, most of them cannot be expected to be good candidates for cogeneration. Although information regarding the total number of apartments with central air conditioning was not available, a lower limit was estimated as follows: The New York State Public Service Commission staff recently identified 120 large steam-consuming apartment buildings that had been placed in the wrong rate class⁴. These apartment buildings were characterized by large summer steam consumption, clearly implying the use central air conditioning. Hence, there are at least 120 large apartment buildings in Con Ed's service territory that are potential candidates for cogeneration. It is reasonable to assume that there are additional apartments using other types of central air conditioning systems that are also potential candidates.

The market penetration projections used in this analysis are not intended to be predictions of the actual market penetration of cogeneration. Rather, two projections for each type of cogeneration are selected to see how the impact on the utility varies with the level of penetration. The two projections span a broad range of possible market penetrations. The higher penetration projection represents a reasonable upper limit on the market penetration given the results of the market potential analysis. The lower projection levels off at about half the maximum penetration level of the higher projection.

The market penetration projections are shown in Figures 8A and B. The effect of these market penetrations on Con Ed loads is to reduce annual generation by about 5 and 10% by the year 2000 for the lower and higher market penetrations respectively. (See Table 2.)

5 MODELLING THE CON ED SYSTEM

The method of analysis used employs the Wien Automatic System Planning Model (WASP) -- a utility capacity planning optimization model -- to compute the utility's future "revenue requirements" (costs that can to be recovered through rates) and fuel consumption. To properly model the utility, information is required regarding the utility's existing system, its future options, and its ties to other utilities. However, all of this information is readily available either in published documents or from the utility.

This chapter describes the sources of the data used in the utility analysis and the assumptions that were employed regarding Con Ed's interchanges of power with other utilities. A discussion of the treatment of transmission and distribution capacity expenditures is contained in Appendix D and a description of the adjustments made for line losses can be found in Appendix E.

5.1 Data Sources

WASP requires detailed technical and cost data regarding the utility's existing generating system and estimates of loads, fuel and plant costs, and

Figure A

Figure B

Figures 8 A & B. Market penetration projections for cogeneration in apartment buildings (A) and office buildings (B).

Table 2

CHARACTERISTICS OF THE MARKET PENETRATION PROJECTIONS:
IMPACT ON CON ED'S LOADS IN YEAR 2000
Units: % reduction in load

	----- Apartment -----		----- Office -----	
	Lower Penetration	Higher Penetration	Lower Penetration	Higher Penetration
Annual Generation	5.5	9.5	5.4	11.0
Summer Peak	3.2	5.6	9.8	14.8
Winter Peak	4.0	6.9	7.4	14.5

capacity options for the future. These data, as used in this study, are tabulated in Appendix F. With the exception of the load forecast, all of this information was obtained either from published sources or from the New York State Public Service Commission. The official Con Ed load forecast available at the time this study began was judged to be unrealistically high, and a lower forecast developed by Energy Systems Research Group, Inc. for this study was employed instead. This latter forecast was quite similar to that adopted by the New York State Energy Office in developing the State's energy master plan.⁶ During the course of this study, Con Ed made major downward revisions in its own load the forecast.

5.2 Power Interchanges With Other Utilities

Con Ed, like most U.S. utilities, is a member of a pool and exchanges power with other utilities. Consequently, estimating changes in Con Ed's costs due to modifications in its loads requires a consideration of its purchases and sales to other utilities. In some respects, Con Ed's relationships to other utilities are unusually complex.

Con Ed shares loads in the New York City area with the Power Authority of the State of New York (PASNY). Since 1975, when PASNY purchased several plants from Con Ed, PASNY has assumed responsibility for meeting municipal loads in New York City. However, the distinction between the two utilities in the downstate area is more of an accounting fiction than a technical reality. PASNY plants are dispatched jointly with Con Ed plants and send power along a common transmission and distribution system to meet a joint load. For all practical purposes, the two systems can be treated as a single unit; municipal loads are identified and accounted for monetarily long after dispatch has actually occurred. Because of the joint dispatch, the sharing of generating units, and the common transmission and distribution system, the Con Ed

and the downstate PASNY systems were modeled as one unit. It is important to note that in computing incremental changes in Con Ed's costs due to incremental changes in Con Ed's loads, the presence or absence of the PASNY system, which remains unaffected by the modifications, has no effect.*

In addition to its intimate relationship with PASNY, Con Ed purchases large amounts of power from Hydro-Quebec during the summer. Hydro-Quebec is a winter-peaking utility and has a sizable excess capacity during the summer when Con Ed is experiencing its peak loads. Con Ed has contracted with Hydro-Quebec for 780 MW of firm summer capacity providing 3 billion kWh per year through 1991 and assumes that those contracts will be continued to the year 2000. In addition, Con Ed expects a one-third share of the non-firm "economy" purchases the New York Power Pool makes from Hydro-Quebec. These economy purchases are expected to be 3 billion kWh/year through 1983, 9 billion kWh/year from 1984 to 1987, and 3 billion kWh/year between 1988 and 2000. In modeling the firm purchases, 780 MW of continuous power was assumed to be provided to Con Ed for about a 23-week period centered on the summer. Following Con Ed's own treatment of economy purchases, we assumed that these were uniformly spread throughout the year.

Con Ed also assumes that a small amount of additional economy energy (about 600,000 megawatt-hours per year) will be available and this input was also spread uniformly throughout the year.

6 UTILITY COST IMPACTS

6.1 Scenarios

To assess the effects of cogeneration on Con Ed's costs, the changes that would occur in Con Ed's revenue requirement if cogeneration systems were installed in apartment and office buildings are computed. Several scenarios of cogeneration use are compared to a base case scenario in which no cogeneration is assumed to have been used. For each of the four market penetration projections shown in Figures 7A and 7B (two for each building), two scenarios are analyzed; one assuming the buildings have cut themselves off from Con Ed electricity ("independent cogeneration") and one in which they are assumed to be connected to the grid ("interconnected cogeneration"). For the interconnected cogeneration cases, the long-run marginal costs† are computed in two ways: One computation follows the FERC "simultaneous buy/sell" approach in which the facility continues to purchase all of its electrical needs from the utility at conventional rates and sells all of its cogenerated power to the facility at rates based on avoided costs. For this situation, the marginal value of the gross output of the cogeneration system (i.e., the avoided cost)

*The PASNY generation system is baseloaded and, hence, not affected by small changes in load.

†Since the marginal costs computed in this study are all long-run marginal costs, they will, henceforth, be referred to simply as "marginal costs", the "long-run" being understood.

is computed. The other computation follows a more conventional approach and examines only the net power interactions between the utility and the facility; in this case, the marginal value to the utility of the net power delivered to it and the marginal cost to the utility of supplying the net power delivered by it to the facility are computed.

To give greater meaning to the marginal cost results we also computed the marginal cost of normal load growth; i.e., the incremental change in utility cost due to a small change in load magnitude with a load pattern identical to that of normal growth. This scenario is called "incremental growth."

Output summaries for all of the scenarios are provided in Appendix G. These summaries provide a variety of cost, load, generation capacity and fuel use parameters for each year of the study period. The optimal capacity purchase schedules for all of the scenarios are shown in Table 3.

6.2 Average Cost

The utility's average cost is simply the total annual revenue requirement divided by the total annual generation. It serves as a simple and convenient measure of the economic impact on the utility of a modification to the utility system. If some modification results in a decrease in the average cost without increasing costs elsewhere in the economic system then, barring adverse non-economic impacts, such a modification is clearly desirable. Note that the average cost is not a measure of the utility's financial health. Due to regulatory imperfections, it is possible, for example, for the average cost to decline as the consequence of a modification and, at the same time, for the utility to suffer a financial squeeze because the revenues it collects may drop more rapidly than the decrease in costs.

In Table 4, the ten-year mean (1991-2000) of the average costs for scenarios in which apartment or office buildings cogenerate are compared with the average costs in the base case and in the incremental growth case. Cogeneration in office buildings consistently produces average costs that are lower than the base case average cost and also lower than the average cost in the incremental growth case. This implies that office building cogeneration has a slightly favorable economic impact on the utility; for example, a 5% load reduction (achieved in the year 2000 with our lower market penetration) due to interconnected cogeneration results in a 3% reduction in average costs, equivalent to an annual savings to Con Ed of about \$113 million.* For the apartment building, independent cogeneration also slightly reduces the average cost while interconnected cogeneration slightly increases it. A 5% decrease in loads (again, by 2000 with the lower penetration) due to interconnected

*Note that under the FERC rules, these "savings" must be transferred to the on-site generators since they are a portion of the total avoided costs.

Table 3
ECONOMICALLY OPTIMAL CAPACITY EXPANSION PLANS

Units: Megawatts

Legend: * Conversion to coal C=Coal H =Hydro GT=Gas Turbine
 - Retirement N=Nuclear PS=Pumped Storage G =Geothermal
 O=Oil Steam

	<u>Required Changes^a</u>	<u>Capacity Options^b</u>	<u>Base</u>	<u>Incr. Growth</u>	<u>Indep. Cog. Low Pen.</u>		<u>Inter. Cogen. Low Pen.</u>		<u>Inter. Cog. High Pen.</u>	
					<u>Apt.</u>	<u>Office</u>	<u>Apt.</u>	<u>Office</u>	<u>Apt.</u>	<u>Office</u>
1980										
1981	872C*									
1982	335C*									
1983	461C*									
1984										
1985										
1986										
1987		800PS	400PS	400PS	400PS	400PS	400PS	400PS	400PS	
1988										
1989										
1990		900C	900C	900C	900C	900C	900C	900C	700C	400C
1991										
1992										
1993										
1994										
1995		500C	300C		200C					
1996	-688 0									
1997	-250 0									
1998		400C								
1999										
2000	-300 0									

^aRequired modifications to capacity; all scenarios.

^bCapacity options; can be purchased in year shown or any subsequent year.

Table 4
 IMPACT OF LOAD MODIFICATIONS ON AVERAGE COST*
 Ten-year mean: 1991-2000
 Units: ¢/kWh in 1980 \$

Base Case	8.62	
Decreased Growth Rate [†]	8.56	
	Apartment	Office
--Lower Market Penetration--		
Interconnected Cogeneration	8.66	8.39
Independent Cogeneration	8.59	8.44
--Higher Market Penetration--		
Interconnected Cogeneration	8.69	8.36
Independent Cogeneration	8.59	8.39

$$*Average\ cost = \frac{Total\ Annual\ Revenue\ Requirements}{Total\ Annual\ Generation}$$

Note that the average costs given in this table refer to kilowatt-hours measured at the generation level. As such they differ from the average costs given in succeeding tables which refer to kilowatt-hours measured at the customer level. That is, the average costs in succeeding tables have been adjusted for line losses.

[†]Load shapes are same as in Base Case. Load magnitudes follow slower growth rate.

cogeneration in apartment buildings results in a 0.4% increase in average costs, equivalent to an annual cost to Con Ed of about \$15 million.*

The reason why cogeneration in the to buildings has such different impacts on Con Ed is that there are differences in the operating patterns of the cogeneration systems. The office cogeneration system substitutes for utility power primarily during the daytime and has a marked summer peak in its output -- i.e., it produces power when Con Ed's costs are highest. The apartment system generates more uniformly on a daily and seasonal basis and hence its effect on utility costs is less favorable.

6.3 The Avoided Costs Associated With Cogeneration

In Table 5, the marginal savings to the utility associated with the reduction in its load when conventional customers switch to interconnected cogeneration (i.e., its avoided costs) are compared to the average cost, to the marginal cost of normal load growth and to the marginal cost of meeting the building's load. The avoided costs are expressed in terms of cents per kilowatt hour and refer to the savings the utility experiences for each kilowatt hour of private generation.† The avoided costs are computed for both the gross output of the cogeneration system (appropriate for the simultaneous buy/sell payment scheme) and for the net power delivered to the utility.** All of the cost indices in Table 5 (and subsequent tables) are adjusted for losses as explained in Appendix E. Results both for the period of the mid-1980's (three-year mean, 1983-85) and for the 1990's (ten-year mean, 1991-2000) are shown. The time trends in these cost parameters are shown in Figures 9A and B. These curves show a general upward trend in all costs during the twenty-year study period due to fuel cost escalation.

The avoided cost associated with office cogeneration is nearly 11¢/kWh. Under the FERC rules, this is the rate the office cogenerators should be paid for the gross output of their cogeneration systems if they choose the simultaneous buy/sell payment scheme. Note that this is above Con Ed's average costs. It is close to the marginal cost to the utility of the office load. (This latter result is a straightforward consequence of the close coincidence of the office load and office cogeneration system electrical output. That is, at the margin, the cost to Con Ed of meeting a particular load should be exactly equal to the savings to Con Ed if it received an equal amount of power with the same temporal pattern.)

*Here the average costs rise because of on-site generation. If cogenerators select arbitrage, then they bear the "losses" in lower rates. This would seem to make little sense, however, since they would come out ahead by opting for a net buy/sell payment scheme in which their generation displaces purchases of utility electricity at higher rates than the rates they would have received for sales under arbitrage. Under the net buy/sell scheme, the loss would have to be made up by the other customers. Note that this shift of the losses to the other customers has nothing to do with the FERC rules. Any facility owner has the right to stop buying from the utility at any time; if that results in higher average costs for the utility, then those costs must be borne by other customers.

†In this study, the marginal costs are computed on an annual basis (i.e., the change in annual revenue requirements divided by the change in annual generation). However, the method permits their computation on a seasonal or monthly basis, if desired.

**See Section 8.2 for a discussion of the simultaneous and net payment schemes.

Table 5

COMPARISON OF THE AVOIDED COSTS ASSOCIATED WITH COGENERATION
AND REFERENCE MEASURES OF UTILITY COSTS^a

Units: ¢/kWh in 1980 \$

	--- Early 1980's ^b ---	----- 1990's ^c -----		
Average Cost	9.11	9.94		
Marginal Cost of Normal Growth ^d	10.35	11.10		
	Apartment	Office	Apartment	Office
Marginal Cost of Building Load ^e	8.40	10.45	9.43	10.93
Interconnected Cogeneration:				
Simultaneous Buy/Sell ^f Cogen. to Utility	6.43	10.88	7.45	11.28
Net Buy/Sell ^g				
Utility to Cogen.	-	3.26	-	4.52
Cogen. to utility	4.43	6.27	5.43	6.92

^aMarginal (or avoided cost) = $\frac{\text{Incremental Annual Revenue Requirement}}{\text{Incremental Annual Generation}}$ x (Loss adjustment Factor)

^bThree-year mean 1983-85.

^cTen-year mean 1991-2000.

^dMarginal cost of normal load growth.

^eNote that this is also the reduction in utility costs associated with independent cogeneration by these buildings.

^fMarginal savings to utility. The "avoided cost" associated with the gross output of the cogeneration system.

^gMarginal cost and savings associated with the net interchanges of power to and from cogenerator, respectively. The marginal savings is the "avoided cost" associated with the net output of the cogeneration system.

Figure A

Figure B

Figures 9A & B. The avoided costs (gross) associated with apartment building cogeneration (A) and office building cogeneration (B) compared to the average cost, the incremental cost of load growth and the incremental cost of the building load. Three year moving average plotted as function of time.

The avoided cost for the apartment building is much lower -- about 7¢/kWh. This is lower than the average cost and lower than the marginal cost of the building's load. The electrical output of the cogeneration system in the apartment is not coincident with its electrical load; because of high thermal energy demands in the winter, the simulation shows that the cogeneration device would frequently be run during periods when the apartment building's electrical load is relatively low. Con Ed's load is also low during these periods, and utility generation displaced by apartment cogeneration during such periods is relatively low in cost.

Table 5 also shows the long-run marginal costs associated with the net interchanges of power between the building and Con Ed. (Since the apartment building never purchases electricity, no value is given in the Table for net purchases.) In general, these results are substantially lower than the "simultaneous buy/sell" avoided costs. There are two reasons for this: In some cases the electricity involved in the interchange is off-peak electricity; consequently, the cost impact on the utility is very small. (For example, notice the low cost for supplementary power sales to the office cogenerator; this facility uses supplementary power primarily at night when the absence of thermal loads and the low electrical loads make the operation of the cogeneration system inefficient and costly.) The second factor which reduces the value of power sold by the cogenerator to the utility is that a distribution system charge was applied to power sold by the cogenerator to the utility. This charge comes into effect when the annual peak power from the cogenerator to the utility exceeds the annual peak power from the utility to the cogenerator. This distribution system charge has significantly lowers the value of the power sold by the office cogenerator to the utility.

How robust are these results? Do they vary over time? Do they change with the assumption regarding market penetration, or if future capacity options were modified? Do the relationships between the costs vary substantially if different assumptions are made regarding the utility's fuel and capital costs? We repeated the analysis several times with modified assumptions to see how the results would be affected.

Figures 9A and B show the time trends in the avoided costs. Three year means of the costs are plotted for the period 1984-2000. The plots show only small variations, generally less than 10%, in the real avoided costs over this 16-year period. This is true despite the fact that during this period capacity is being added to the Con Ed system and that oil costs are assumed to be escalating.

Table 6 shows how the marginal costs vary for the two buildings as the market penetration of cogeneration doubles from the low to the high projection. With one exception,* this substantial increase in the market penetration produces less than an 11% change in the cost indices.†

*The net transfer of power from the office cogenerator to the utility, involving a relatively small amount of energy on an annual basis.

†Note however that the "marginal costs" as measured with this method are actually incremental costs; in other words, they are the average of the marginal cost measured as the derivative of the cost function at the production point at which the higher market is assumed to have occurred will show a larger deviation than the incremental cost.

Table 6
IMPACT OF CHANGES IN COGENERATION MARKET PENETRATION ON UTILITY COSTS
Ten-year, 1991-2000, mean of costs
Units: ¢/kWh in 1980 \$

	-----Apartment-----		-----Office-----	
	Lower Penetration ^a	Higher Penetration ^a	Lower Penetration ^b	Higher Penetration ^b
Independent Cogeneration ^c	9.42	9.09	10.93	10.42
Interconnected Cogeneration:				
Simultaneous Buy/Sell				
Cogen. to Utility	7.45	7.44	11.28	10.24
Net Buy/Sell				
Utility to Cogen.	-	-	4.52	5.03
Cogen. to Utility	5.43	5.68	6.92	4.26

^aLower: 340 MW by 2000, Higher: 590 MW by 2000.

^bLower: 1075 MW by 2000, Higher: 2180 MW by 2000.

^cIncremental reduction in utility costs associated with independent cogeneration.

Table 7 shows how the relative structure of the costs varies if fuel and capital cost assumptions are varied or if it is assumed that the capacity expansion schedule is held fixed at the base scenario schedule instead of reoptimized for each load modification scenario. Very little change -- less than 10% -- is observed in the ratio of the simultaneous buy/sell avoided costs to the marginal cost of normal growth as a result of these changes. With one exception, the marginal values and costs associated with the net transfers vary by less than 25%.

Across a variety of changes in assumptions about the future of cogeneration and of the Con Ed system, then, the structure of the results regarding avoided costs and the marginal costs and values associated with net power transfers vary relatively little. Consequently, one can feel confident that, in applying these results to the development of rates for cogeneration, the general structure of the rates will probably not have to be modified (although the absolute levels, of course, would change) if the specific assumptions regarding penetration level, plant and fuel costs, and expansion plan do not turn out to be realistic.

6.4 Capacity and Production Cost Components of Avoided Costs

The FERC has specified that in developing rates for cogeneration and small power production facilities both avoided energy costs and avoided capacity costs be considered. With some methods of computing marginal costs, these must be computed separately. The method used in this study computes the sum of the two in a self-consistent, integrated framework. From the information provided by the WASP model, the two components of the sum can easily be determined. In Tables 8 and 9, these components have been tabulated for the early 1980's and for the 1990's respectively, for the marginal costs associated with cogeneration. For comparison, the components for the average cost, the marginal cost of growth, and for the marginal cost of meeting the building load are also shown. Figures 10 and 11 show the time trends in the components.

There are no changes in the generation capacity plan that could be implemented in the next few years. (see Table 3). Thus, the capacity component of all of the marginal costs in the early 1980's period reflects only the differences in transmission and distribution system investments that result from differences in the peak loads in the various scenarios.* Since office cogeneration has a relatively large effect on peak loads, the capacity-related avoided cost associated with the gross output of this cogenerator is fairly large—about 3¢/kWh, or one-third of the total avoided cost. Also, because the net power flows between the office cogenerator and the utility are primarily off-peak, the capacity portions of the associated marginal costs are small. For apartment cogeneration, which has a relatively smaller effect on peak loads, the avoided capacity cost is much smaller.

By the 1990's, the capacity component of all of the marginal costs and savings is higher, reflecting modifications that can be made to generation capacity additions; the scheduled installation dates of the 750-MW coal-fired plant and the Prattsville pumped storage facility planned for this period can be modified as loads change.

The avoided capacity costs represent a sizable savings to the utility that, when refunded to cogenerators under the simultaneous buy/sell rates, greatly increase their receipts for cogenerated power.

*A discussion of the treatment of transmission and distribution capacity investments is contained in Appendix D.

Table 7

SENSITIVITY OF MARGINAL COSTS TO ASSUMPTIONS

Units: Ratio of Specified Marginal Cost to the Marginal Cost of Normal Growth.

	<u>Base Results</u>	<u>Higher Mkt. Pen.</u>	<u>Higher Costs</u>	<u>Fixed Expansion</u>
----- Apartment -----				
Marginal Cost of Bldg. Load	.92	.87	.92	.92
Simultaneous Buy/Sell	.74	.74	.77	.72
Net Buy/Sell				
Utility to Cogen.	-	-	-	-
Cogen. to Utility	.55	.57	.60	.51
----- Office -----				
Marginal Cost of Bldg. Load	1.04	.99	1.11	1.03
Simultaneous Buy/Sell	1.07	.97	1.11	1.02
Net Buy/Sell				
Utility to Cogen.	.44	.49	.55	.44
Cogen. to Utility	.69	.42	.43	-

Table 8
CAPACITY AND PRODUCTION COST COMPONENTS OF UTILITY COSTS*

Three-year mean: 1983-1985

Units: ¢/kWh in 1980 \$

	Capacity	Production	Total
Average Cost	3.81	3.87	9.11*
Marginal Cost of Growth	3.69	6.66	10.35
-----Apartment-----			
Marginal Cost of Building Load	1.44	6.97	8.40
Interconnected Cogeneration:			
Simultaneous Buy/Sell Cogen. to Utility	0.88	5.55	6.43
Net Buy/Sell			
Utility to Cogen. Cogen. to Utility	--- -0.03	--- 4.46	--- 4.43
-----Office-----			
Marginal Cost of Building Load	3.11	7.34	10.45
Interconnected Cogeneration:			
Simultaneous Buy/Sell Cogen. to Utility	3.36	7.52	10.87
Net Buy/Sell			
Utility to Cogen. Cogen. to Utility	0.00 0.11	3.26 6.14	3.26 6.25

*Total includes a residual for administrative and general overhead.

Table 9

CAPACITY AND PRODUCTION COST COMPONENTS OF UTILITY COSTS

Ten-year mean: 1991-2000

Units: ¢/kWh in 1980 \$

	Capacity	Production	Total
Average Cost	4.48	4.11	9.95*
Marginal Cost of Growth	5.40	5.70	11.10
-----Apartment-----			
Marginal Cost of Building Load	2.82	6.60	9.42
Interconnected cogeneration:			
Simultaneous Buy/Sell Cogen. to Utility	2.63	4.81	7.45
Net Buy/Sell			
Utility to Cogen.	---	---	---
Cogen. to Utility	1.99	3.44	5.43
-----Office-----			
Marginal Cost of Building Load	3.92	7.01	10.93
Interconnected Cogeneration:			
Simultaneous Buy/Sell			
Cogen. to Utility	5.62	5.66	11.28
Net Buy/Sell			
Utility to Cogen.	0.17	4.35	4.52
Cogen. to Utility	19.40	-12.47	6.92
*Total includes a residual for administrative and general overhead.

Figure A

Figure B

, Figures 10A & B. Capacity and production cost components of the average cost of electricity (A) and the incremental cost of load growth (B). Three year moving average plotted as a function of time.

Figure A

Figure B

Figures 11 A & B. Capacity and production cost components of the avoided cost (gross) associated with interconnected cogeneration in the apartment building (A) and the office building (B). Three year moving average plotted as a function of time.

7 FUEL USE IMPACTS

Cogenerating devices are very efficient in their consumption of fuel compared to the separate production of heat and electricity. However, most cogenerating systems, especially those likely to be used in the types of commercial applications considered here, consume oil or gas. A facility switching to cogeneration will use more of these fuels than it previously did in its boilers. On the other hand, the utility will generate less electricity and will be consuming less fuel. Whether the net result is a savings or an increase in the use of oil and gas depends strongly on the utility generating mix.

It is an explicit goal of national energy policy to reduce the consumption of oil and gas, especially oil and particularly in the commercial and industrial sectors. An increase in the overall use of oil and gas as a consequence of a shift to cogeneration would be undesirable in this context. What is the net effect on the consumption of oil and gas fuels due to cogeneration in apartment and office buildings in the Con Ed territory?

The changes in fuel use by the facility and the utility when apartment and office buildings convert from the conventional purchase of utility electricity to interconnected cogeneration are shown in Table 10. Changes in the net annual use of oil are detailed for the three-year periods 1983-1985 and 1993-1995. The cumulative change resulting from a building that is converted in 1980 and that uses cogeneration for 20 years is also shown.* For the purpose of these calculations, it was assumed that the facility used fuel oil in its boilers before converting to cogeneration.† The time trends in the annual and cumulative fuel use are plotted in Figures 12 and 13.

Office building cogeneration can save approximately 1/2 million gallons of oil per year per building in the mid-1980's and apartment building cogeneration about 1.2 millions gallons per year. Although the annual savings decline through the 1980's and turn into a net increase in oil use in all cases by the year 2000, the cumulative savings in oil associated with a building that converts to cogeneration in 1980 and continues to cogenerate to 2000 is positive for all cases.

8 ANALYSIS OF PROPOSED RATES

In addition to their use in developing class-differentiated rates, the the marginal costs computed in this study can be used to check whether or not a proposed rate structure is consistent with the utility's long-run marginal costs and savings. For example, if a time-differentiated rate structure has been developed, then, using the hourly generation and load patterns obtained from the simulation model, the payments that

*In order to make the utility and the facility fuel use data compatible, the utility fuel consumption data from the WASP model was adjusted for line losses as described in Appendix E.

†Gas and utility steam are also used to provide thermal energy in New York City. Buildings using gas would have the same changes in total oil and gas use as those denoted for oil on these tables. For buildings using utility steam, the computations are complicated by the fact that most of the steam used in NYC is generated in utility-owned cogenerating plants.

Table 10

CHANGES IN FUEL USE PATTERNS WHEN FACILITY CONVERTS FROM
UTILITY ELECTRICITY TO INTERCONNECTED COGENERATION*

Units: 10^9 Btu/year per building**

	---Apartment---		-----Office-----	
	Oil	Coal & Nuclear	Oil	Coal & Nuclear
-----Early 1980's-----				
Facility [†]	+145		+66	
Utility	-308	-100	-138	-11
Net change	-163	-100	-72	-11
-----Early 1990's-----				
Facility [†]	+145		+66	
Utility	-218	-174	-68	-85
Net change	-73	-174	-2	-85
-----Cumulative change 1980-2000 [#] -----				
Facility [†]	+3045		+1398	
Utility	-5407	-3074	-1961	-1212
Net change	-2362	-3074	-564	-1212

*The results in this table are for the low market penetration cases.

**Except for cumulative sum which are in units of 10^9 Btu per building.

[†]Boiler and/or diesel fuel used at the facility.

[#]Cumulative change for one building converting in 1980 and cogenerating through the year 2000.

Figure A

Figure B

Figures 12A & B. Annual (A) and cumulative (B) oil savings due to apartment building cogeneration. Savings are the net of the combined facility and utility oil use per building. Positive numbers imply reductions in oil use; negative numbers, increases.

Figure A

Figure B

Figures 13A & B. Annual (A) and cumulative (B) oil savings due to office building cogeneration. Savings are the net of the combined facility and utility oil use per building. Positive numbers imply reductions in net use; negative numbers, increases.

facility owners would make to the utility and their receipts from the utility for power sold to the utility could be computed on an annual basis. Similarly, the long-run marginal costs can also be converted into annual payments and receipts. In this way, various proposed rate structures can easily be compared to each other and to the results of this analysis.

8.1 Rate Structures Analyzed

Several existing and proposed rate structures are pertinent to the generic On-Site Generation Case currently being conducted by the New York State Public Service Commission. We compared our results to rate structures that have been proposed by the staff of the Public Service Commission and by Con Ed and also to existing rate structures. The Public Service Commission staff has proposed a rate structure for cogenerators who were previously in the SC-8 (apartment buildings) or SC-9 (office buildings) rate classes.* For the apartment building, the existing SC-8 rate structure for purchases of electricity by the facility were combined with Con Ed's proposed buy-back rates for sales by the facility to the utility. For the office building, both the existing SC-9 rates and Con Ed's proposed SC-9 rate were combined with Con Ed's proposed buy-back rate. These rate structures are detailed in Appendix C.

8.2 Simultaneous Vs. Net Payment Schemes

For each of the staff and Con Ed rate structures, we computed the payments and receipts in two ways: One method assumes arbitrage; i.e., that the cogenerators selected the simultaneous buy/sell situation in which they continue paying Con Ed for all of their electricity use (as if they were a conventional customer) while selling to Con Ed the gross output of their cogenerating device. The other assumed that the customer would choose a net buy/sell payment structure; here, the cogenerators pay Con Ed only for their net requirements for utility power and sell to Con Ed only that cogenerated power that is in excess of the facility's internal consumption. Note that although the placement of meters will differ between these two payment schemes, the physical flows of power will not change.

The reason why there are two possible payment schemes for the same physical situation is as follows: In most U.S. utilities, marginal costs are substantially above average costs. If rates for purchase by a facility were based on a conventional cost allocation approach while the rates for sales by a cogenerator were based on marginal costs, the cogenerators would generally receive much less for power sold to the utility under a net buy/sell scheme than under a simultaneous buy/sell scheme. This is because in the former case the cogenerated electricity is considered to displace the facility's purchases of power (at the lower average cost-based rates), whereas in the latter case it is instead sold to the utility at the higher marginal cost based rates.

*The version of those rates prior to a revision in the staff's assumption regarding the capital carrying charge was used for comparison; the earlier version was used because the capital carrying charge assumption used was consistent with the assumption used in this study.

The FERC in its Order No. 69 stated that to achieve the goals enunciated in PURPA regarding the encouragement of alternative power producing technologies, it was desirable for cogenerators and small power producers to receive the marginal avoided costs for all of their generation, not just a portion of it. Hence, they devised the simultaneous buy/sell payment scheme to accomplish this.

However, this scheme is unnecessary if the rates for the purchase and the sale of electricity by a cogenerator are both based on marginal costs and if marginal costs for purchase are not adjusted by a revenue requirement correction. In such a situation, there should be no difference in the net of the payments and receipts between the two schemes; hence, there would be no need for two separate rate structures. Since the New York Commission is moving in the direction of marginal cost pricing for all rates, and since the staff has determined that a revenue requirement adjustment is not needed, the staff has proposed one rate structure for on-site generation with distribution system charges appropriate for the net buy/sell situation. Although we computed the payments and receipts for the staff rates for both the simultaneous and the net buy/sell schemes as a matter of interest, only the results for the latter are meaningful.

8.3 Comparison of Payments Under the Various Rates

The payments under the various rate structures are shown in Table 11. For all of the rate structures, an economically rational cogenerator would always choose the net buy/sell payment scheme over the simultaneous payment scheme. The financial incentive for so doing is an additional several hundred thousand dollars a year in net income. As mentioned above, it is clear why there should be a disparity in the case of the PSC staff's proposed rates; they were not designed to account for the distribution system credits accruing to a cogenerator in the simultaneous buy/sell situation. Since Con Ed's intentions regarding the application of its rate structure are not clear, it is not known whether the gross or the net payment scheme was supposed to be used with these rates. It has been assumed that the net scheme was intended to be used.

When compared to the existing rates for apartments and Con Ed's proposed rates for office buildings, the staff's proposed rates provide for greater payments for conventional purchases (\$74,000 per year or 6.5% more for the apartment, \$92,000 per year or 11% more for the office building). The staff rates also provide a greater incentive to switch to cogeneration than do either of the others when the latter are combined with Con Ed's proposed buy-back rate (\$103,000 per year or 5% more for the apartment, \$155,000 per year or 20% more for the office building). Note, however, that Con Ed's proposed conventional purchase rates for office buildings are substantially lower than the existing rates; they result in a 20% reduction (\$180,000 per year) in the office building owner's payments for electricity compared to the existing rates. This reduction reduces the incentive to switch to cogeneration by \$193,000 per year. This is a significant reduction which would substantially lower a facility owner's rate of return on a cogeneration system investment.

The long-run marginal costs computed in the Brookhaven study for the period of the mid-1980's yield payments for conventional purchases that are about 10% higher than payments under the staff rates. The Brookhaven results also yield a greater change in payments to the cogenerators (2% higher for the apartment cogenerator and 15% for the office cogenerator).

Table 11

FACILITY OWNER'S ANNUAL PAYMENTS AND RECEIPTS:
COMPARISON OF VARIOUS RATE STRUCTURES WITH LONG RUN MARGINAL COSTS:

Units: \$1000's

		Conventional	----- Cogenerator -----				
	Rate Structure	Purchases	Net/ Gross	Purchases	Sales	Net ^a	Overall Change*
----- Apartment -----							
LRMC ^c	1980's	1326					2256
	1990's	1489					2615
SC-8	Rate 2/C.E. ^d	1129	Gross	1129	1836	707	1836
SC-8	Rate 1/C.E. ^d	N.A ^e	Net	0	981	981	2110
PSC		1203	Gross	1203	1949	746	1949
PSC		1203	Net	0	1010	1010	2213
----- Office -----							
LRMC ^c	1980's	988					1074
	1990's	1034					1113
SC-9	TOD Current/ C.E. ^d	998	Gross	1086	674	-412	586
SC-9	Current/C.E. ^d	N.A ^e	Net	81	51	- 30	968
SC-9	TOD Proposed/ C.E. ^d	818	Gross	896	674	-222	596
SC-9	Proposed/C.E. ^d	N.A ^e	Net	94	51	- 43	775
PSC		910	Gross	992	781	-211	699
PSC		910	Net	50	70	20	930

^aNet of purchases and sales.

^bOverall change in facility owner's annual payments in switching from conventional purchases of electricity to interconnected cogeneration.

^cAnnual payments and receipts assuming rates were based on long run marginal costs computed in this study. Results are shown using LRM C's for the 1980's and the 1990's as given in Table 4.

^d"C.E." refers to Con Ed's proposed buy back rate.

^eNot applicable; the building, in a conventional purchase situation, is not eligible for this purchase rate.

The Brookhaven marginal costs yield a much larger change in the payments that would be experienced by an office building owner converting to cogeneration than the change produced by Con Ed's proposed rates. Both the buy-back rate and the rate for conventional purchases proposed by Con Ed differ considerably from the Brookhaven results and both do so in a manner that discourages cogeneration.

9 REFERENCES

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APPENDIX A
OFFICE BUILDING SPECIFICATIONS

Architecture

Shape	Rectangular (100 ft. x 200 ft), with narrow facade facing due north.
Height	31 occupied stories, 13 ft floor-to-floor, 9-ft. ceilings. 2 stories below grade for storage. Common ceiling plenums on each floor.
Areas (gross)	Building total of 660,000 ft ² each.
Structure	Steel frame with concrete floors.
Mechanical space	Penthouse contains all mechanical, electrical, and elevator equipment.
Floors	Bottom floor is 4-in. concrete on soil. All others are 4-in. concrete.
Exterior walls	Insulated curtain wall. Spandrell glass 6-1/2 ft high. Rigit 1-in. insulation.
Roof	Built-up roofing on concrete, insulated.
Ceiling	Suspended acoustical tile with lay-in flourescent light fixtures.
Windows	Double-glazed, 1/4-in. grey outside, regular sheet inside. Windows are 6-1/2 ft high on every floor, and run the full width of each wall.
Partitions	Heat transfer between adjacent zones is assumed to be negligible.
Underground wall	Effective U-Value=0.05.
Underground floor	Effective U-Value=0.05.
Window glass	1/4-in. grey sheet outside, regular sheet inside. Shading coefficient is 0.86.

Interior Conditions

Lighting	Recessed fluorescent, 3 W/ft ² , 20 PC heat to ceiling plenum.
Receptacles	0.18 W/ft ²
People	100 ft ² /person in exterior zones, 200 ft ² /person in interior zones, no one in storage areas.

APPENDIX A (continued)

Schedules

Occupancy	Building is occupied only between 7 a.m. and 8 p.m. It is fully occupied from 7 a.m. to 4 p.m., except for a drop at and around the lunch hour. After 4 p.m., it drops off except for the maintenance crew.
Lighting	It is close to 100% during the day, with a slight depression at lunch. After 4 p.m. it steps down steadily to 20% at 10 p.m., and near 0 after midnight.
Office equip.	On only from 7 a.m. to 8 p.m. At about 50% during the morning, 75% in the afternoon, and about 1/3 in the evening maintenance period.
Infiltration	Infiltration is 0.2 air changes per hour when the fans are on, and 0.5 air changes per hour when the fans are off. Infiltration is zero in the storage areas.

HVAC System

Description	One double-duct constant volume system supplies the entire building. Insulated ducts to ceiling outlets. Return air taken from common ceiling plenums on each floor. System has temperature-controlled economizer cycle, econo-limit-temp is 72°F. Max humidity ratio is 0.009. Min humidity ratio is 0.001.
Design temperatures	Cooling 76°F drybulb. Heating 74°F drybuld.
Supply air	105°F during heating if outside temp is below 40°F. Reset proportionately lower (min 70°F) for outside temperatures up to 90°F. 55°F during cooling. Maximum air flow based on summation of non-coincident peak air requirements. Draw thru supply fans with 6.5 inches of water static pressure, and 63%. Overall efficiency. Storage area has a constant air flow supplying 4 air changes per hour.
Return air	2.0 inches of water static pressure, and 66 PC overall fan efficiency.
Ventilation	Minimum of 7 cfm/person outside air when the supply fans are on. 1/2 outside air change per hour in storage area.
Controls	System to operate weekdays only, except holidays. System turned on at 7 a.m. and shut off at 6 p.m. Winter setback to 50°F. Summer float to 99°F. Proportional thermostat with 2°F throttling range.

APPENDIX B

COGENERATION SYSTEM OUTPUT AS FUNCTION OF INSTALLED CAPACITY

Capacity		Building Load		Cogen. Output		Absorption	"System"
Electrical	Absorption	Electrical	Thermal	Electrical	Thermal ^a	Chiller	Size ^c
(MW)	Chiller (Tons)	(GWH/yr)	(10 ⁹ Btu/yr)	(GWH/yr)	(10 ⁹ Btu/yr)	Fraction ^b (%)	
-- Apartment --							
1.5	1600	15.8	227.5	13.1	10.5	80	0.41
2.9	1600	15.8	227.5	25.1	15.7	80	0.78
4.4	1600	15.8	227.5	35.1	22.8	80	1.19
5.8	1600	15.8	227.5	42.6	27.4	80	1.57
10.5	1600	15.8	227.5	53.5	32.0	80	2.84
-- Office --							
1.5	270	11.0	13.4	5.7	50.7	15	0.37
2.5	540	10.8	19.2	8.6	96.8	30	0.61
4.3	875	10.6	25.6	11.0	135.1	50	1.05
5.5	1200	10.4	31.2	12.1	164.1	67	1.34
7.3	1500	10.3	33.7	13.3	205.5	85	1.78

^aPortion of thermal output utilized.

^bFraction of total chiller capacity composed of absorption units.

^cRatio of peak electrical output to peak electrical load

APPENDIX C

RATE STRUCTURES

- Notes: 1) All energy (kWh) charges have been adjusted to include 2¢/kWh fuel adjustment
2) All rates are given for primary customers only.
3) Summer rating period is May 15 - Oct. 15. Winter rating period is remainder of year.

CHART C-1

PSC STAFF PROPOSED RATES*

Applies to SC-8 (apartment building) and SC-9 (office buildings) class customers who convert to cogeneration.

Rating Periods

SP (summer peak):	12 noon - 6 pm, Mon-Fri.
SS (summer shoulder):	8 AM - 12 noon, 6 PM - 10 PM, Mon-Fri.
SO (summer off-peak):	All other hours of week
WP (winter peak):	8 AM - 10 PM, Mon-Fri.
WO (winter off-peak):	All other hours of week.

Utility to Cogenerator

	<u>SP</u>	<u>SS</u>	<u>SO</u>	<u>WP</u>	<u>SO</u>
Energy Charge (¢/kWh):	7.6	6.9	4.8	6.6	4.4

Demand Charge (\$/kW per year applied to the maximum demand during summer peak period):

Apartment	\$90.91
Office	\$76.00

Cogenerator to Utility

	<u>SP</u>	<u>SS</u>	<u>SO</u>	<u>WP</u>	<u>SO</u>
Energy Charge (¢/kWh):	13.5	6.3	4.5	6.1	4.2

Demand Charge: None (Transmission credit included in SP energy charge. No distribution credit provided).

*The rates given here are not the final rates proposed by the PSC staff. The final rates proposed were based on a 12% fixed charge rate while the rates given here were based on a 22% fixed charge rate. The difference between the two rates are in the transmission and distribution charges. The energy charges remain unchanged.

CHART C-2

EXISTING SC-8 (APARTMENT BUILDING) RATES

Applies to the purchase of electricity by SC-8 customers.

Rating Periods

Peak: 8 AM - 10 PM, Mon-Fri.
Off-peak: All other hours of week

Rate 1

Applicable to customers with annual maximum demand less than 3000 kW.

Energy Charge (¢/kWh)

First 80,000 kWh/month	6.08
Next 720,000	5.62
Excess over 800,000	5.21

Demand Charge (\$ per maximum kW per month)

Summer:	12.00
Winter:	9.00

Rate 2

Applicable to customers with annual maximum demand greater than 3000 kW.

Energy Charge (¢/kWh)

SP	5.64
SO	4.66
WP	5.92
WO	4.66

Demand Charge (\$ per maximum kW per month during rating period)

Summer - 8 AM - 6 PM, Mon-Fri:	13.74
6 PM - 10 PM, Mon-Fri:	5.81
Other hours:	0.0
Winter - 8 AM - 10 PM, Mon-Fri:	5.81
Other hours:	0.0

CHART C-3

EXISTING AND PROPOSED SC-9 (OFFICE BUILDING) RATES

Applies to purchase of electricity by SC-9 customers with maximum demand under 1300 kW. (Used in this study to apply to net purchases by a cogenerator.)

--- Existing ---

Energy Charge (\$/kWh)

First 1,500,000 kWh	6.15
Over 1,500,000 kWh	6.01

Demand Charge (\$ per maximum kW per month)

Summer:	First 1300 kW of maximum demand	12.71
	Over 1300 "	12.02
Winter:	First 1300 kW of maximum demand	9.71
	Over 1300 "	9.02

--- Proposed ---

Energy Charge (\$/kWh)

All kWh:	5.51
----------	------

Demand Charge (\$ per maximum kW per month)

	<u>Summer</u>	<u>Winter</u>
First 300 kW of max. demand	17.41	14.41
Next 600	12.00	9.00
Over 900	10.00	7.00

CHART C-4

EXISTING AND PROPOSED SC-9 (OFFICE BUILDING) TIME OF DAY RATES

Applies to purchase of electricity by SC-9 customers with maximum demand over 1300 kW. (Used in this study to apply to conventional purchase situation and to purchases under simultaneous buy/sell situation.)

Rating Periods

Peak: 8 AM - 10 PM, Mon-Fri.
Off-peak: All other hours of week.

--- Existing ---

Energy Charge (¢/kWh)

<u>SP</u>	<u>SO</u>	<u>WP</u>	<u>WO</u>
5.64	4.66	5.92	4.66

Demand Charge (\$ per maximum kW demand per month)

Summer:	8 AM - 6 PM, Mon-Fri.	17.71
	6 PM - 10 PM, "	7.06
	Other	0.0
Winter:	8 AM - 10 PM, Mon-Fri.	7.06
	Other	0.0

--- Proposed ---

Energy Charge (¢/kWh)

No charge.

Demand Charge (\$ per maximum kW demand per month)

Summer:	8 AM - 6 PM	11.01
	6 PM - 10 PM	4.22
	Other	0.0
Winter:	8 AM - 10 PM	4.22

APPENDIX D

TRANSMISSION AND DISTRIBUTION CHARGES

Transmission and distribution system charges and credits were allocated in the following way: First, a transmission and distribution system investment cost was assumed to be incurred by Con Ed as its load grew; this cost was assumed to be proportional to the annual peak load experienced by Con Ed. The transmission system cost used was $T = \$134.64$ per peak kW and the distribution system cost was $D = \$512.48$ per peak watt; both figures were obtained from the PSC staff. Half of the distribution system cost was assumed to be associated with the primary level and half with the secondary level. For either primary or secondary customers, one-half of the cost for that level (i.e., $D/4$) was assumed to be directly customer-related and half related to the general distribution system.

All cogenerators were assumed to be connected at the primary level. It was assumed that they had been connected at the secondary level prior to conversion to cogeneration. Transmission system investments were assumed to be reduced due to cogeneration in proportion to the reduction in Con Ed's peak loads. However, it was never assumed that transmission system investments would drop below the maximum investment experienced in any previous year even if the absolute level of the peak load dropped below a previously established peak level.

For normal load growth and for the marginal cost of the building load, the full $T + D$ charge was used. For the simultaneous buy/sell situation, a credit equal to $T + D/2$ was included in the avoided costs with the following exception: The cogenerator was assumed to be responsible for paying for additional hook-up costs (equal to $D/4$) incurred to the utility if the peak net power flow from the cogenerator to the utility was greater than the peak net power flow from the utility to the cogenerator. For the net buy case, a charge of $T + D/2$ was applied. The net sell case was treated in the same way as the simultaneous buy/sell.

APPENDIX E

LOSS ADJUSTMENT FACTORS

Because of power losses in transmission and distribution, a kilowatt-hour of power consumed on-site or generated on-site increases or reduces, respectively, the need for utility generation by an amount greater than 1 kilowatt-hour. The marginal and average cost indices and the utility fuel consumption must be adjusted by a loss adjustment multiplier to account for these losses. The losses vary depending on the load on the system, and on which point in the transmission and distribution system they are measured.

It is assumed that all cogeneration systems connect to the primary distribution system. Cogenerated power used on-site is given a credit for all losses that would have been incurred by the utility in delivering power to a primary customer. The multiplier used is a weighted combination of the loss factors for the various time periods given in the column "On-site" in the table below. The weighting factor used in computing the multiplier is a product of the fraction of the total number of hours in a year in a given time period and the fraction of the total annual on-site generation during each time period. Cogenerated power delivered to the primary system (not used on-site) incurs losses in the primary grid before being used by another customer. Hence this power is assigned a smaller credit, shown in the column "Delivered to Primary". The marginal cost of the building load and the utility to cogenerator net buy/sell marginal costs are adjusted using the "on-site" factors. The cogenerator to utility net buy/sell avoided costs are adjusted by the "delivered to primary" factors. The simultaneous buy/sell avoided costs are adjusted by a weighted combination of the appropriate "on-site" and "delivered to primary factors" where the weighting coefficients are the fraction of the generation that is used on-site or delivered to primary, respectively. The average costs and the marginal cost of normal load growth are adjusted using the total loss factors appropriate for secondary system customers, as given in the column "Secondary," weighted by the fraction of the total annual generation that occurs in each period.

Loss Factors by Time Period

	<u>Hours in Period</u>	<u>On-Site^a</u>	<u>Delivered To Primary^b</u>	<u>Secondary^a</u>
Summer Peak	1542	1.100	1.047	1.187
Winter Peak	2148	1.090	1.043	1.169
Summer Off-peak	2106	1.061	1.029	1.112
Winter Off-peak	2964	1.057	1.027	1.104

^aObtained from p. 1 of Exhibit MOB-5 of testimony of Dr. Miles Bidwell in Case 27352 — Phase II Consolidated Edison Company before the State of New York Public Service Commission.

^bObtained by adjusting the "on-site" figures for losses in the primary system.

Loss Adjustment Multipliers

Average Load	1.154	
	<u>Apartment</u>	<u>Office</u>
Building Load	1.082	1.094
Simultaneous buy/sell	1.051	1.094
Net buy/sell		
Utility to cogen.	-	1.059
Cogen. to utility	1.033	1.035

APPENDIX F

Input Parameters Used in Modelling The Con Ed System

Table F-1

BASE FORECAST OF LOAD GROWTH

Year	Summer Peak (MW)	Winter Peak (MW)	Annual Energy (GWh)
1980	8055	6395	37,870
1985	8750	6950	40,800
1990	9015	7220	42,040
1995	9170	7380	42,700
2000	9260	7500	43,210
<hr/>			
	Growth Rate (%/year)		
1980-1990	1.1	1.2	0.8
1991-2000	0.2	0.4	0.3

Table F-2

EXISTING CAPACITY

Plant		Capacity (MW)*	Heat Rate (Btu/kWh) ⁺	F.O.R. (%)#	1980 Variable Cost (\$/MWh)
Indian Pt.	3	942	11,203	18.0	6.20
	2	858	11,539	18.0	6.30
Fitzpatrick		180	11,000	18.0	6.10
Astoria	6	702	10,407	15.8	53.30
	5	325	11,670	15.8	59.70
	4	350	10,936	15.0	56.00
	3	331	10,875	15.0	55.70
	1&2	300	12,628	12.5	64.70
Bowline	1&2	752	9,860	13.5	50.50
Arthur Kill	3	461	10,385	9.8	53.20
	2	335	10,934	11.5	56.00
Ravenswood	3	872	10,830	12.4	55.40
	1&2	740	10,563	9.7	54.10
Roseton	1&2	460	9,560	13.5	42.10
East River	7	161	11,934	11.1	61.10
	5&6	250	18,494	14.7	94.70
Waterside		320	16,000	33.0	81.90
Hudson Ave	5&10	86	20,000	33.0	102.40
	7&8	282	20,000	33.0	102.40
74th St.		126	16,000	66.0	81.90
59th St.		92	17,000	6.0	87.00
Gas Turbines (7 units)		1812	14,732	20.0	87.93
			to 18,470		to 109.23

*Capacity is maximum. Units modeled in two blocks with minimum loading levels.

+Heat rate is at full load.

#F.O.R. is full load equivalent including daily unavailability.

Variable cost includes fuel and variable O&M at full load.

Table F-3

FUTURE CAPACITY OPTIONS

I Coal Capacity

Year ^a	Possible Capacity ^b (MW)	Heat Rate (Btu/kWh)	F.O.R. (%)	1980 Variable Cost (\$/MWh)	1980 Capital Cost (\$/kW)
1990	900	10,163	14.0	20.5	920
1995	500	10,163	14.0	20.5	920
1998	400	10,163	14.0	20.5	920

II Pumped Storage

Year	Possible Capacity (MW)	Efficiency (%)	1980 Capital Cost (\$/kW)
1987	800	75%	450

^aFirst year in which capacity can be selected for optimal expansion schedule.

Model may defer introduction to later years.

^bModel may choose less capacity if optimal.

Table F-4

SCHEDULE OF OPTIMAL CAPACITY ADDITIONS IN BASE CASE

1987	400 MW Pumped Storage
1990	900 MW Coal
1995	300 MW Coal

Table F-5
FUEL COST ASSUMPTIONS

	1980 Cost (¢/10 ⁶ Btu)	---Annual Escalation Rate--- (%/year)		
		1980- 1985	1986- 1995	1996- 2000
Low-Sulfur Residual	512	2.0	2.0	0.5
Medium-Sulfur Residual	440	2.0	2.0	0.5
Distillate	569	2.0	2.0	0.5
Coal	202	2.6	0.2	0.2
Nuclear	55	0.0	0.0	0.0

Table F-6
FIRM AND ECONOMY PURCHASES FROM HYDRO-QUEBEC^a

Year	Capacity ^b (MW)	Energy ^c (GWh/year)
1980-83	895	3800
1984-87	1245	5800
1988-2000	955	3797

^aSeasonal variation not shown

^bSummer maximum

^cAnnual total

APPENDIX G

OUTPUT SUMMARIES

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Table G-1
BASE
LOAD AND COST DATA

YEAR	PEAK LOAD	ANNUAL GEN.	ANNUAL LOAD FACTOR	RESERVE MARGIN	PROD COST		CAPITAL COST			TOTAL COST	
	(MW)	(GWH)	(%)	(%)	ANNUAL (EGJ)	UNIT (C/KWH)	GEN (EGJ)	T&D (EGJ)	CUMUL UNIT (C/KWH)	ANNUAL (EGJ)	UNIT (C/KWH)
1980	8055	38468	54.5	43.0	1471	3.83	0	0.0	3.20	3213	8.35
1981	8227	39145	54.3	39.6	1444	3.69	0	111.3	3.23	3216	8.22
1982	8377	39750	54.2	37.1	1404	3.53	0	97.1	3.27	3212	8.08
1983	8515	40331	54.1	34.6	1391	3.45	0	89.3	3.31	3235	8.02
1984	8630	40862	54.1	32.4	1330	3.26	0	74.4	3.30	3191	7.81
1985	8753	41399	54.0	30.5	1382	3.34	0	79.6	3.30	3260	7.87
1986	8817	41708	54.0	29.3	1426	3.42	0	41.4	3.30	3313	7.94
1987	8878	42016	54.0	32.5	1434	3.41	185	39.5	3.39	3370	8.02
1988	8928	42308	54.1	31.8	1581	3.74	0	32.4	3.39	3525	8.33
1989	8977	42498	54.0	30.7	1626	3.83	0	31.7	3.39	3577	8.42
1990	9014	42639	54.0	40.2	1478	3.47	852	23.9	3.83	3621	8.49
1991	9050	42787	54.0	39.5	1504	3.52	0	23.3	3.83	3652	8.54
1992	9072	42912	54.0	39.3	1528	3.56	0	14.2	3.83	3679	8.57
1993	9113	43073	54.0	38.7	1555	3.61	0	26.5	3.82	3712	8.62
1994	9141	43184	53.9	38.2	1579	3.66	0	18.1	3.82	3740	8.66
1995	9167	43300	53.9	41.1	1550	3.58	284	16.8	3.97	3777	8.72
1996	9180	43394	54.0	33.4	1534	3.54	0	8.4	3.93	3749	8.64
1997	9211	43521	53.9	30.3	1530	3.52	0	20.1	3.91	3743	8.60
1998	9231	43604	53.9	30.0	1539	3.53	0	12.9	3.91	3755	8.61
1999	9251	43707	53.9	29.7	1550	3.55	0	12.9	3.91	3769	8.62
2000	9262	43805	54.0	26.3	1556	3.55	0	7.1	3.89	3770	8.61

NOTE RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)					ENERGY OUTPUT (GIGAWATT-HOURS)					FUEL CONSUMPTION		
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	(E9 BTU) RESID COAL
1980	1812	6945	0	1980	0	197	20664	0	12509	4400	0	2986	223441 0
1981	1812	6073	872	1950	0	372	17910	3508	12250	4400	0	5658	194771 38191
1982	1812	5738	1207	1950	0	387	15668	6374	12220	4400	0	5899	170313 68415
1983	1812	5277	1668	1920	0	533	13745	8920	12018	4400	0	8114	150325 94858
1984	1812	5277	1668	1890	0	265	12548	9281	11675	6400	0	4033	136237 98121
1985	1812	5277	1668	1890	0	313	12510	9372	11717	6400	0	4762	140512 99054
1986	1812	5277	1668	1860	0	351	13248	9459	11568	6400	0	5348	144489 99948
1987	1812	5277	1668	1830	400	195	13225	10249	11601	6400	1006	2969	142881 107976
1988	1812	5277	1668	1830	400	442	14912	10648	11620	4397	1197	6695	161672 112065
1989	1812	5277	1668	1800	400	502	15198	10697	11432	4397	1229	7594	164866 112564
1990	1812	5277	2568	1800	400	127	11616	14715	11400	4397	895	1922	126327 153570
1991	1812	5277	2568	1800	400	135	11736	14751	11402	4397	900	2043	127677 153933
1992	1812	5277	2568	1800	400	140	11832	14763	11401	4397	892	2129	128720 154054
1993	1812	5277	2568	1800	400	150	11942	14811	11404	4397	895	2283	130000 154539
1994	1812	5277	2568	1800	400	157	12016	14834	11404	4397	904	2383	130851 154775
1995	1812	5277	2868	1800	400	104	11007	16055	11389	4397	934	1586	119870 167295
1996	1812	4589	2868	1800	400	152	11039	16061	11388	4397	964	2323	120021 167363
1997	1812	4339	2868	1800	400	165	11013	16224	11399	4397	994	2531	119417 169009
1998	1812	4339	2868	1800	400	170	11062	16243	11406	4397	991	2606	119947 169199
1999	1812	4339	2868	1800	400	177	11128	16261	11400	4397	986	2719	120654 169376
2000	1812	4039	2868	1800	400	290	11104	16264	11400	4397	983	4449	119615 169410

Table G-2
Incremental Growth
LOAD AND COST DATA

YEAR	PEAK LOAD	ANNUAL GEN	ANNUAL LOAD FACTOR	RESERV MARGIN	PROD ANNUAL	COST UNIT	CAPITAL ADDITIONS		COST CUMUL	TOTAL COST	
	(MW)	(GWH)	(%)	(%)	(EGJ)	(C/KWH)	GEN (EGJ)	TRD (EGJ)	UNIT (C/KWH)	ANNUAL (EGJ)	UNIT (C/KWH)
1980	8053	38457	54.5	43.0	1470	3.82	0	0.0	3.20	3212	8.35
1981	8214	39090	54.3	39.8	1440	3.69	0	104.2	3.23	3211	8.22
1982	8340	39586	54.2	37.7	1394	3.52	0	81.5	3.27	3197	8.08
1983	8428	39949	54.1	35.9	1368	3.43	0	56.9	3.31	3200	8.01
1984	8481	40207	54.1	34.7	1295	3.22	0	34.3	3.31	3134	7.80
1985	8541	40471	54.1	33.8	1329	3.29	0	38.8	3.31	3177	7.85
1986	8543	40507	54.1	33.4	1356	3.35	0	1.3	3.30	3204	7.91
1987	8544	40552	54.2	37.7	1346	3.32	185	.6	3.40	3235	7.98
1988	8532	40571	54.3	37.9	1465	3.61	0	-0.0	3.40	3354	8.27
1989	8531	40542	54.3	37.6	1491	3.68	0	0.0	3.40	3380	8.34
1990	8517	40458	54.2	48.4	1356	3.35	852	0.0	3.87	3432	8.49
1991	8528	40496	54.2	48.2	1367	3.38	0	7.1	3.87	3445	8.51
1992	8536	40566	54.3	48.0	1384	3.41	0	5.2	3.87	3464	8.54
1993	8578	40727	54.2	47.3	1408	3.46	0	27.2	3.87	3493	8.58
1994	8605	40838	54.2	46.9	1428	3.50	0	17.5	3.87	3517	8.61
1995	8631	40954	54.2	46.4	1450	3.54	0	16.8	3.87	3543	8.65
1996	8644	41048	54.2	38.2	1433	3.49	0	8.4	3.82	3513	8.56
1997	8675	41175	54.2	34.9	1435	3.49	0	20.1	3.81	3514	8.53
1998	8695	41258	54.2	34.5	1445	3.50	0	12.9	3.81	3526	8.55
1999	8715	41361	54.2	34.2	1455	3.52	0	12.9	3.81	3539	8.56
2000	8726	41460	54.2	30.6	1462	3.53	0	7.1	3.78	3541	8.54

NOTE: RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)					ENERGY OUTPUT (GIGAWATT-HOURS)					FUEL CONSUMPTION		
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	(E9 BTU) RESID COAL
1980	1812	6945	0	1980	0	196	20653	0	12509	4400	0	2976	223327 0
1981	1812	6073	872	1950	0	364	17867	3506	12249	4400	0	5533	194302 38166
1982	1812	5738	1207	1950	0	352	15563	6356	12216	4400	0	5366	169165 68226
1983	1812	5277	1668	1920	0	472	13486	8873	12006	4400	0	7180	147402 94377
1984	1812	5277	1668	1890	0	216	12109	9169	11622	6400	0	3290	131212 96987
1985	1812	5277	1668	1890	0	239	12287	9218	11643	6400	0	3632	133268 97478
1986	1812	5277	1668	1860	0	255	12437	9263	11476	6400	0	3873	135033 97944
1987	1812	5277	1668	1830	400	122	12086	9987	11576	6400	887	1856	130433 105317
1988	1812	5277	1668	1830	400	233	13566	10432	11606	4397	1029	3538	146805 109849
1989	1812	5277	1668	1800	400	236	13690	10474	11418	4397	1039	3591	148234 110283
1990	1812	5277	2568	1800	400	59	10156	14093	11366	4397	873	891	110333 147331
1991	1812	5277	2568	1800	400	54	10690	14215	11377	4397	895	815	109555 148548
1992	1812	5277	2568	1800	400	55	10145	14221	11376	4397	893	834	110130 148606
1993	1812	5277	2568	1800	400	60	10245	14283	11380	4397	897	906	111223 149226
1994	1812	5277	2568	1800	400	63	10312	14315	11381	4397	898	959	111950 149550
1995	1812	5277	2568	1800	400	63	10401	14356	11382	4397	901	964	112938 149964
1996	1812	4589	2568	1800	400	102	10430	14365	11381	4397	897	1557	113033 150049
1997	1812	4339	2568	1800	400	105	10518	14423	11385	4397	907	1615	114014 150636
1998	1812	4339	2568	1800	400	109	10567	14448	11386	4397	917	1678	114542 150884
1999	1812	4339	2568	1800	400	114	10634	14470	11386	4397	920	1759	115268 151109
2000	1812	4039	2568	1800	400	192	10663	14482	11386	4397	986	2952	114945 151229

Table G-3
Building Load-Apartment (also Independent Cogeneration)

LOAD AND COST DATA

YEAR	PEAK LOAD	ANNUAL GEN	ANNUAL LOAD FACTOR	RESERV MARGIN	PROD COST		CAPITAL COST		TOTAL COST	
	(MW)	(KWH)	(%)	(%)	ANNUAL (£63)	UNIT (C/KWH)	ADDITIONS GEN (£63)	CUMUL TRD UNIT (£63)	ANNUAL (£63)	UNIT (C/KWH)
1980	8052	38452	54.5	43.0	1470	3.82	0	0.0	3212	8.35
1981	8219	39098	54.3	39.8	1440	3.69	0	110.1	3212	8.22
1982	8361	39656	54.1	37.4	1397	3.52	0	93.9	3204	8.08
1983	8485	40157	54.0	35.0	1380	3.44	0	83.8	3222	8.02
1984	8578	40561	54.0	33.2	1312	3.24	0	65.8	3168	7.81
1985	8679	40974	53.9	31.7	1354	3.31	0	71.0	3226	7.87
1986	8721	41155	53.9	30.7	1368	3.37	0	32.8	3266	7.94
1987	8760	41337	53.9	34.3	1387	3.36	185	30.9	3313	8.02
1988	8788	41503	53.9	33.9	1517	3.66	0	23.8	3449	8.31
1989	8818	41581	53.8	33.1	1553	3.74	0	24.3	3490	8.39
1990	8836	41612	53.8	43.0	1411	3.39	852	16.5	3540	8.51
1991	8867	41729	53.7	42.5	1433	3.44	0	21.3	3566	8.55
1992	8886	41839	53.7	42.2	1454	3.48	0	13.1	3590	8.58
1993	8927	42000	53.7	41.6	1479	3.52	0	26.5	3621	8.62
1994	8955	42111	53.7	41.1	1501	3.57	0	18.1	3647	8.66
1995	8981	42227	53.7	42.9	1492	3.54	189	16.8	3683	8.72
1996	8994	42320	53.7	35.1	1470	3.47	0	8.4	3647	8.62
1997	9025	42448	53.7	31.8	1470	3.46	0	20.1	3647	8.59
1998	9045	42530	53.7	31.6	1481	3.48	0	12.9	3660	8.61
1999	9065	42633	53.7	31.3	1492	3.50	0	12.9	3674	8.62
2000	9076	42732	53.7	27.8	1498	3.51	0	7.1	3675	8.60

NOTE RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)					ENERGY OUTPUT (GIGAWATT-HOURS)					FUEL CONSUMPTION		
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	(£5 BTU) RESID COAL
1980	1812	6945	0	1980	0	196	20649	0	12509	4400	0	2972	223277
1981	1812	6073	872	1950	0	265	17866	3505	12248	4400	0	5548	194306
1982	1812	5738	1287	1950	0	270	15587	6360	12216	4400	0	5637	169413
1983	1812	5277	1668	1920	0	500	13620	8899	12011	4400	0	7609	148923
1984	1812	5277	1668	1850	0	243	12326	9220	11642	6400	0	3697	133662
1985	1812	5277	1668	1850	0	276	12579	9283	11671	6400	0	4201	136665
1986	1812	5277	1668	1850	0	202	12802	9345	11510	6400	0	4595	139288
1987	1812	5277	1668	1830	400	155	12615	10112	11585	6400	963	2362	136197
1988	1812	5277	1668	1830	400	226	14180	10543	11611	4397	1114	4940	153496
1989	1812	5277	1668	1800	400	363	14383	10583	11422	4397	1141	5501	155797
1990	1812	5277	2568	1800	400	89	10804	14425	11380	4397	928	1344	117393
1991	1812	5277	2568	1800	400	93	10890	14456	11381	4397	919	1417	118337
1992	1812	5277	2568	1800	400	97	10976	14459	11380	4397	918	1472	119247
1993	1812	5277	2568	1800	400	104	11085	14506	11383	4397	909	1579	120462
1994	1812	5277	2568	1800	400	109	11161	14527	11384	4397	909	1659	121302
1995	1812	5277	2768	1800	400	78	10567	15271	11378	4397	928	1177	115047
1996	1812	4589	2768	1820	400	115	10499	15407	11386	4397	948	1751	113871
1997	1812	4339	2768	1800	400	129	10559	15456	11388	4397	958	1977	114480
1998	1812	4339	2768	1800	400	134	10619	15487	11389	4397	968	2058	115129
1999	1812	4339	2768	1800	400	140	10689	15514	11390	4397	971	2156	115910
2000	1812	4039	2768	1800	400	221	10709	15518	11389	4397	1008	3398	115457

Table G-4
Building Load-Office (also Independent Cogeneration)
LOAD AND COST DATA

YEAR	PEAK LOAD (MW)	ANNUAL GEN (GWH)	ANNUAL LOAD FACTOR (%)	RESERV MARGIN (%)	PROD COST		CAPITAL COST			TOTAL COST	
					ANNUAL (€6€)	UNIT (C/KWH)	GEN (€6€)	T&D (€6€)	CUMUL UNIT (C/KWH)	ANNUAL (€6€)	UNIT (C/KWH)
1980	8051	38457	54.5	43.1	1471	3.83	0	0.0	3.20	3213	8.36
1981	8209	39093	54.4	39.9	1441	3.69	0	106.9	3.23	3212	8.22
1982	8322	39592	54.3	38.0	1393	3.52	0	62.6	3.27	3197	8.08
1983	8388	39960	54.4	36.6	1366	3.42	0	61.2	3.31	3199	8.01
1984	8412	40225	54.6	35.8	1290	3.21	0	38.8	3.31	3132	7.79
1985	8444	40497	54.7	35.3	1320	3.26	0	44.0	3.31	3172	7.83
1986	8417	40541	55.0	35.4	1341	3.31	0	23.3	3.32	3198	7.89
1987	8390	40594	55.2	40.3	1333	3.26	185	22.5	3.43	3235	7.97
1988	8350	40621	55.5	40.9	1445	3.56	0	23.1	3.44	3353	8.25
1989	8326	40598	55.7	41.0	1467	3.62	0	18.7	3.45	3379	8.32
1990	8286	40517	55.8	52.5	1332	3.29	852	19.7	3.93	3435	8.48
1991	8266	40560	55.9	52.5	1340	3.31	0	9.2	3.93	3446	8.50
1992	8296	40632	56.0	52.4	1357	3.34	0	7.2	3.93	3464	8.53
1993	8331	40793	55.9	51.7	1379	3.38	0	26.5	3.93	3492	8.56
1994	8359	40903	55.9	51.2	1398	3.42	0	18.1	3.93	3516	8.60
1995	8385	41019	55.8	50.7	1420	3.46	0	16.8	3.93	3540	8.63
1996	8398	41113	55.9	42.3	1404	3.42	0	8.4	3.89	3511	8.54
1997	8429	41240	55.9	38.8	1404	3.41	0	20.1	3.87	3510	8.51
1998	8449	41323	55.8	38.5	1412	3.42	0	12.9	3.87	3522	8.52
1999	8469	41425	55.8	38.1	1424	3.44	0	12.9	3.87	3536	8.54
2000	8480	41525	55.9	34.4	1427	3.44	0	7.1	3.85	3534	8.51

*NOTE RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW.

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)					ENERGY OUTPUT (GIGAWATT-HOURS)					FUEL CONSUMPTION		
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	(€9 BTU) RESID COAL
1980	1812	6945	0	1980	0	196	20660	0	12510	4400	0	2971	223398 0
1981	1812	6073	872	1950	0	361	17880	3508	12249	4400	0	5480	194421 38184
1982	1812	5738	1207	1950	0	343	15565	6366	12219	4400	0	5224	169138 68337
1983	1812	5277	1668	1920	0	438	13498	8906	12015	4400	0	6660	147459 94722
1984	1812	5277	1668	1890	0	192	12066	9231	11662	6400	0	2915	130599 97612
1985	1812	5277	1668	1890	0	201	12198	9295	11685	6400	0	3051	132058 98264
1986	1812	5277	1668	1860	0	204	12292	9348	11512	6400	0	3093	133082 98811
1987	1812	5277	1668	1830	400	90	11929	10008	11585	6400	769	1360	128614 105546
1988	1812	5277	1668	1830	400	161	13428	10423	11611	4397	910	2447	144892 109753
1989	1812	5277	1668	1800	400	160	13526	10441	11422	4397	905	2434	145954 109938
1990	1812	5277	2568	1800	400	36	9840	14087	11372	4397	783	555	106847 147272
1991	1812	5277	2568	1800	400	29	9738	14214	11382	4397	796	445	105764 148545
1992	1812	5277	2568	1800	400	30	9790	14209	11380	4397	789	455	106305 148496
1993	1812	5277	2568	1800	400	33	9894	14263	11384	4397	795	498	107411 149238
1994	1812	5277	2568	1800	400	35	9956	14312	11385	4397	796	528	108068 149528
1995	1812	5277	2568	1800	400	37	10033	14353	11386	4397	798	559	108894 149940
1996	1812	4589	2568	1800	400	58	10101	14370	11386	4397	795	881	109530 150111
1997	1812	4339	2568	1800	400	64	10168	14413	11388	4397	796	976	110251 150545
1998	1812	4339	2568	1800	400	67	10218	14432	11389	4397	793	1022	110773 150733
1999	1812	4339	2568	1800	400	70	10299	14460	11390	4397	787	1080	111625 151012
2000	1812	4039	2568	1800	400	117	10353	14470	11390	4397	827	1803	111474 151119

Table G-5
Interconnected Cogeneration, Low Penetration-Apartment

LOAD AND COST DATA

YEAR	PEAK LOAD	ANNUAL GEN	ANNUAL LOAD FACTOR	RESERV MARGIN	PROD ANNUAL	COST UNIT	CAPITAL ADDITIONS GEN	CGST T&D	CUMUL UNIT	TOTAL COST	
	(MW)	(GWH)	(%)	(%)	(EG\$)	(C/KWH)	(EG\$)	(EG\$)	(C/KWH)	ANNUAL (EG\$)	UNIT (C/KWH)
1980	8051	38433	54.5	43.1	1469	3.82	0	0.0	3.21	3211	8.36
1981	8214	39046	54.3	39.8	1437	3.68	0	109.5	3.23	3209	8.22
1982	8351	39541	54.1	37.6	1392	3.52	0	92.6	3.28	3198	8.09
1983	8467	39945	53.9	35.3	1371	3.43	0	81.7	3.33	3211	8.04
1984	8547	40195	53.7	33.7	1296	3.23	0	62.4	3.35	3151	7.84
1985	8635	40459	53.5	32.3	1333	3.29	0	67.6	3.36	3202	7.91
1986	8664	40486	53.3	31.5	1360	3.36	0	29.4	3.37	3235	7.99
1987	8690	40513	53.2	35.4	1346	3.32	185	27.5	3.49	3269	8.07
1988	8706	40530	53.1	35.2	1465	3.62	0	20.6	3.50	3393	8.37
1989	8724	40475	53.0	34.5	1494	3.69	0	21.1	3.51	3425	8.46
1990	8730	40371	52.8	44.8	1356	3.36	852	13.4	3.99	3478	8.62
1991	8757	40449	52.7	44.3	1374	3.40	0	20.3	4.00	3501	8.66
1992	8775	40540	52.7	44.0	1391	3.43	0	12.8	4.00	3520	8.68
1993	8816	40700	52.7	43.3	1417	3.48	0	26.5	3.99	3553	8.73
1994	8844	40811	52.7	42.9	1438	3.52	0	18.1	3.99	3577	8.77
1995	8870	40927	52.7	42.5	1460	3.57	0	16.8	3.99	3603	8.81
1996	8883	41021	52.7	34.5	1444	3.52	0	8.4	3.95	3573	8.71
1997	8914	41148	52.7	31.2	1445	3.51	0	20.1	3.93	3574	8.69
1998	8934	41231	52.7	30.9	1448	3.51	0	12.9	3.93	3580	8.68
1999	8954	41334	52.7	30.7	1455	3.52	0	12.9	3.93	3589	8.69
2000	8965	41432	52.8	27.2	1465	3.54	0	7.1	3.91	3595	8.68

NOTE RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)					ENERGY OUTPUT (GIGAWATT-HOURS)					FUEL CONSUMPTION		
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	(EG BTU) RESID COAL
1980	1812	6945	0	1980	0	195	20631	0	12508	4400	0	2960	223085 0
1981	1812	6073	872	1950	0	359	17822	3502	12246	4400	0	5455	193807 38128
1982	1812	5738	1207	1950	0	365	15518	6346	12212	4400	0	5557	168633 68131
1983	1812	5277	1668	1920	0	482	13508	8863	12002	4400	0	7334	147683 94272
1984	1812	5277	1668	1890	0	229	12124	5149	11609	6400	0	3484	131394 96779
1985	1812	5277	1668	1890	0	257	12316	9189	11627	6400	0	3912	133667 97190
1986	1812	5277	1668	1860	0	278	12465	9223	11456	6400	0	4233	135439 97535
1987	1812	5277	1668	1830	400	133	12071	5965	11567	6400	932	2024	130253 105090
1988	1812	5277	1668	1830	400	262	13522	10403	11599	4397	1050	3982	146478 109549
1989	1812	5277	1668	1800	400	288	13651	10434	11410	4397	1072	4373	147936 109872
1990	1812	5277	2568	1800	400	69	10169	14030	11349	4397	920	1054	110443 146683
1991	1812	5277	2568	1800	400	73	10223	14051	11349	4397	923	1101	111034 146896
1992	1812	5277	2568	1800	400	73	10259	14064	11349	4397	925	1116	111393 147027
1993	1812	5277	2568	1800	400	82	10394	14127	11353	4397	930	1239	112898 147660
1994	1812	5277	2568	1800	400	85	10458	14167	11356	4397	936	1294	113608 148014
1995	1812	5277	2568	1800	400	89	10536	14198	11358	4397	947	1359	114475 148373
1996	1812	4589	2568	1800	400	130	10564	14212	11357	4397	942	1988	114558 148508
1997	1812	4339	2568	1800	400	150	10632	14261	11360	4397	963	2300	115238 149001
1998	1812	4339	2568	1800	400	141	10589	14389	11371	4397	975	2161	114673 150287
1999	1812	4339	2568	1800	400	143	10612	14415	11372	4397	979	2202	114909 150546
2000	1812	4339	2568	1800	400	232	10668	14427	11372	4397	1036	3572	114902 150666

Table G-6
Interconnected Cogeneration, Low Penetration-Office

LOAD AND COST DATA

YEAR	PEAK LOAD	ANNUAL GEN	ANNUAL LOAD FACTOR	RESERV MARGIN	PROD	COST	CAPITAL COST			TOTAL COST	
	(MW)	(GWH)	(%)	(%)	ANNUAL (E\$)	UNIT (C/KWH)	ADDITIONS GEN (E\$)	TSD (E\$)	CUMUL UNIT (C/KWH)	ANNUAL (E\$)	UNIT (C/KWH)
1980	8051	38457	54.5	43.1	1471	3.83	0	0.0	3.20	3213	8.36
1981	8206	39090	54.4	40.0	1440	3.68	0	106.1	3.23	3211	8.22
1982	8313	49586	54.4	38.2	1392	3.52	0	81.0	3.27	3195	8.07
1983	8367	39949	54.5	36.9	1364	3.42	0	58.0	3.31	3196	8.00
1984	8377	40207	54.8	36.4	1288	3.20	0	35.3	3.31	3128	7.78
1985	8395	40471	55.0	36.1	1317	3.26	0	40.3	3.31	3166	7.82
1986	8353	40507	55.4	36.4	1338	3.30	0	29.0	3.32	3193	7.88
1987	8313	40552	55.7	41.5	1329	3.28	185	27.4	3.43	3231	7.97
1988	8258	40571	56.1	42.5	1441	3.55	0	29.1	3.45	3350	8.26
1989	8223	40542	56.3	42.7	1458	3.60	0	22.9	3.46	3371	8.32
1990	8173	40458	56.5	52.2	1345	3.33	663	23.4	3.84	3410	8.43
1991	8167	40496	56.6	52.3	1361	3.36	0	11.5	3.85	3428	8.47
1992	8167	40566	56.7	52.3	1379	3.40	0	6.1	3.84	3448	8.50
1993	8208	40727	56.6	51.5	1403	3.45	0	26.5	3.84	3477	8.54
1994	8236	40838	56.6	51.0	1424	3.49	0	18.1	3.84	3502	8.58
1995	8262	40954	56.6	50.5	1447	3.53	0	16.8	3.84	3528	8.62
1996	8275	41048	56.6	42.0	1431	3.49	0	8.4	3.80	3500	8.53
1997	8306	41175	56.6	38.4	1425	3.46	0	20.1	3.78	3493	8.48
1998	8326	41258	56.6	38.1	1441	3.49	0	12.9	3.78	3511	8.51
1999	8346	41361	56.6	37.8	1453	3.51	0	12.9	3.78	3526	8.53
2000	8357	41460	56.6	34.0	1451	3.50	0	7.1	3.76	3519	8.49

NOTE: RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)					ENERGY OUTPUT (GIGAWATT-HOURS)					FUEL CONSUMPTION (9 BTU)		
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	RESID COAL
1980	1812	6945	0	1980	0	195	20660	0	12510	4400	0	2970	223397
1981	1812	6073	872	1950	0	359	17870	3507	12249	4400	0	5463	194321
1982	1812	5738	1207	1950	0	340	15552	6368	12219	4400	0	5181	168981
1983	1812	5277	1668	1920	0	431	13483	8909	12016	4400	0	6563	147283
1984	1812	5277	1668	1890	0	189	12034	9232	11662	6400	0	2867	130250
1985	1812	5277	1668	1890	0	196	12157	9297	11687	6400	0	2983	131603
1986	1812	5277	1668	1860	0	196	12251	9352	11515	6400	0	2983	132640
1987	1812	5277	1668	1830	400	86	11876	10005	11587	6400	760	1302	128064
1988	1812	5277	1668	1830	400	154	13388	10424	11612	4397	886	2336	144425
1989	1812	5277	1668	1800	400	154	13396	10433	11422	4397	880	2338	144536
1990	1812	5277	2368	1800	400	38	10317	13499	11395	4397	765	577	111850
1991	1812	5277	2368	1800	400	38	10344	13520	11396	4397	760	579	112131
1992	1812	5277	2368	1800	400	38	10406	13525	11395	4397	751	579	112791
1993	1812	5277	2368	1800	400	42	10522	13568	11398	4397	750	646	114012
1994	1812	5277	2368	1800	400	45	10602	13593	11399	4397	747	679	114873
1995	1812	5277	2368	1800	400	47	10691	13621	11400	4397	744	718	115822
1996	1812	4589	2368	1800	400	73	10754	13624	11399	4397	739	1120	116373
1997	1812	4339	2368	1800	400	80	10725	13770	11407	4397	759	1227	115882
1998	1812	4339	2368	1800	400	85	10883	13675	11402	4397	750	1301	117735
1999	1812	4339	2368	1800	400	89	10969	13698	11403	4397	741	1373	118728
2000	1812	4039	2368	1800	400	142	10917	13805	11408	4397	808	2176	117259

Table G-7
Interconnected Cogeneration, High Penetration-Apartment

LOAD AND COST DATA

YEAR	PEAK LOAD (MW)	ANNUAL GEN (GWH)	ANNUAL LOAD FACTOR (%)	RESERV MARGIN (%)	PROD ANNUAL (E6\$)	COST UNIT (C/KWH)	CAPITAL COST		TOTAL COST	ANNUAL (E6\$)	UNIT (C/KWH)
							ADDITIONS GEN (E6\$)	CUMUL T2D (E6\$)			
1980	8051	38433	54.5	43.1	1469	3.82	0	0.0	3.21	3211	8.36
1981	8205	38970	54.2	40.0	1434	3.68	0	106.3	3.24	3205	8.23
1982	8333	39400	54.0	37.8	1385	3.52	0	89.6	3.29	3190	8.10
1983	8440	39735	53.7	35.7	1359	3.42	0	78.6	3.34	3198	8.05
1984	8512	39920	53.5	34.2	1283	3.22	0	59.7	3.36	3135	7.85
1985	8583	40037	53.3	33.1	1308	3.27	0	61.7	3.39	3174	7.93
1986	8595	39930	53.0	32.6	1330	3.33	0	23.5	3.41	3200	8.02
1987	8603	39818	52.8	36.8	1308	3.29	185	21.4	3.53	3224	8.10
1988	8601	39695	52.7	36.8	1417	3.57	0	15.8	3.55	3337	8.41
1989	8606	39534	52.4	36.4	1434	3.63	0	16.6	3.58	3357	8.49
1990	8604	39360	52.2	44.5	1329	3.38	663	11.9	3.97	3401	8.64
1991	8601	39199	52.0	44.6	1335	3.41	0	11.8	3.99	3409	8.70
1992	8597	39114	51.9	44.7	1344	3.44	0	7.9	4.00	3420	8.75
1993	8624	39170	51.8	44.2	1361	3.48	0	21.8	4.01	3442	8.79
1994	8635	39140	51.7	44.0	1374	3.51	0	12.2	4.02	3457	8.83
1995	8652	39186	51.7	43.7	1391	3.55	0	13.7	4.02	3478	8.88
1996	8665	39280	51.7	35.6	1375	3.50	0	8.4	3.98	3448	8.78
1997	8696	39407	51.7	32.2	1375	3.49	0	20.1	3.96	3447	8.75
1998	8716	39491	51.7	31.9	1385	3.51	0	12.9	3.96	3460	8.76
1999	8736	39593	51.7	31.6	1395	3.53	0	12.9	3.96	3473	8.77
2000	8747	39692	51.8	28.0	1402	3.53	0	7.1	3.94	3474	8.75

NOTE RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)					ENERGY OUTPUT (GIGAWATT-HOURS)					FUEL CONSUMPTION		
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	(E9 BTU) RESID COAL
1980	1812	6945	0	1980	0	195	20631	0	12508	4400	0	2960	223085 0
1981	1812	6073	872	1950	0	354	17776	3499	12244	4400	0	5383	193286 38096
1982	1812	5730	1207	1950	0	356	15418	6328	12206	4400	0	5415	167500 67943
1983	1812	5277	1668	1920	0	455	13378	8828	11993	4400	0	6928	146226 93916
1984	1812	5277	1668	1890	0	216	11957	9095	11583	6400	0	3286	129545 96230
1985	1812	5277	1668	1890	0	230	12019	5104	11588	6400	0	3507	130275 96316
1986	1812	5277	1668	1860	0	247	12112	9111	11398	6400	0	3759	131379 96390
1987	1812	5277	1668	1830	400	113	11560	9815	11547	6400	921	1718	124745 103571
1988	1812	5277	1668	1830	400	204	12923	10263	11583	4397	1000	3111	139995 108117
1989	1812	5277	1668	1800	400	209	12934	10272	11393	4397	1010	3181	140173 108214
1990	1812	5277	2368	1800	400	72	10196	13003	11330	4397	925	1093	110605 136234
1991	1812	5277	2368	1800	400	70	10110	12535	11322	4397	929	1068	109684 135581
1992	1812	5277	2368	1800	400	68	10071	12686	11315	4397	927	1038	109240 135052
1993	1812	5277	2368	1800	400	72	10103	12507	11317	4397	934	1096	109600 135258
1994	1812	5277	2368	1800	400	73	10082	12867	11313	4397	938	1102	109384 135057
1995	1812	5277	2368	1800	400	75	10119	12901	11314	4397	940	1137	109790 135196
1996	1812	4589	2368	1800	400	112	10159	12915	11314	4397	935	1713	110015 135340
1997	1812	4334	2368	1800	400	123	10223	12963	11319	4397	941	1681	110684 135005
1998	1812	4339	2368	1800	400	128	10273	12988	11321	4397	947		
1999	1812	4334	2368	1800	400	138	10333						
2000	1812	4049	2368	1800	400								

Table G-8
Interconnected Cogeneration, High Penetration-Office
LOAD AND COST DATA

YEAR	PEAK LOAD (MW)	ANNUAL GEN (GWH)	ANNUAL LOAD FACTOR (%)	RESERV MARGIN (%)	PROD COST		CAPITAL COST			TOTAL COST	
					ANNUAL (E6\$)	UNIT (C/KWH)	ADDITIONS GEN (E6\$)	T&D (E6\$)	CUMUL UNIT (C/KWH)	ANNUAL (E6\$)	UNIT (C/KWH)
1980	8051	38457	54.5	43.1	1471	3.83	0	0.0	3.20	3213	8.36
1981	8202	39079	54.4	40.1	1440	3.68	0	104.5	3.23	3210	8.22
1982	8309	39576	54.4	38.2	1392	3.52	0	81.2	3.27	3195	8.07
1983	8363	39938	54.5	37.0	1363	3.42	0	57.9	3.31	3195	8.00
1984	8356	40152	54.9	36.8	1285	3.20	0	53.6	3.31	3124	7.78
1985	8327	40296	55.2	37.2	1305	3.24	0	41.5	3.32	3153	7.83
1986	8248	40233	55.7	38.2	1317	3.28	0	39.1	3.35	3174	7.89
1987	8161	40158	56.2	39.3	1328	3.31	0	40.6	3.38	3194	7.95
1988	8083	40115	56.7	40.6	1421	3.54	0	34.7	3.40	3294	8.21
1989	8005	39977	57.0	41.6	1437	3.60	0	34.8	3.43	3318	8.30
1990	7916	39791	57.4	48.3	1366	3.44	378	34.3	3.68	3339	8.39
1991	7904	39666	57.3	48.5	1374	3.47	0	6.3	3.69	3348	8.44
1992	7891	39529	57.2	48.7	1381	3.50	0	2.3	3.70	3355	8.49
1993	7894	39416	57.0	48.7	1390	3.53	0	5.4	3.72	3365	8.54
1994	7892	39309	56.9	48.7	1399	3.56	0	7.7	3.73	3376	8.59
1995	7887	39195	56.7	48.8	1408	3.59	0	7.9	3.75	3386	8.64
1996	7873	39081	56.7	40.3	1380	3.53	0	6.9	3.72	3345	8.56
1997	7887	39091	56.6	36.9	1373	3.51	0	13.4	3.72	3335	8.53
1998	7891	39064	56.5	36.9	1376	3.52	0	6.7	3.72	3340	8.55
1999	7896	39057	56.5	36.8	1381	3.54	0	7.1	3.73	3347	8.57
2000	7892	39047	56.5	33.6	1376	3.53	0	3.8	3.71	3336	8.54

NOTE RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)					ENERGY OUTPUT (GIGAWATT-HOURS)					FUEL CONSUMPTION		
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	(E9 BTU) RESID COAL
1980	1812	6945	0	1980	0	195	20660	0	12510	4400	0	2970	223397 0
1981	1812	6073	872	1950	0	357	17868	3507	12250	4400	0	5428	194294 38182
1982	1812	5738	1207	1950	0	340	15549	6368	12220	4400	0	5174	168941 68354
1983	1812	5277	1668	1920	0	428	13476	8908	12016	4400	0	6519	147193 94738
1984	1812	5277	1668	1890	0	184	11998	9231	11665	6400	0	2793	129835 97610
1985	1812	5277	1668	1890	0	181	12003	9273	11671	6400	0	2751	129873 98045
1986	1812	5277	1668	1860	0	171	11995	9310	11489	6400	0	2592	129762 98416
1987	1812	5277	1668	1830	0	163	11961	9331	11309	6400	0	2480	129350 98639
1988	1812	5277	1668	1830	0	253	13006	9921	11476	4397	0	3852	141116 104627
1989	1812	5277	1668	1800	0	230	13045	9965	11297	4397	0	3496	141532 105076
1990	1812	5277	2068	1800	0	108	11263	11677	11271	4397	0	1643	121992 122606
1991	1812	5277	2068	1800	0	101	11174	11683	11271	4397	0	1527	121042 122667
1992	1812	5277	2068	1800	0	93	11077	11664	11269	4397	0	1410	119987 122473
1993	1812	5277	2068	1800	0	97	10981	11675	11272	4397	0	1469	118952 122588
1994	1812	5277	2068	1800	0	91	10897	11671	11271	4397	0	1384	118067 122542
1995	1812	5277	2068	1800	0	87	10819	11667	11271	4397	0	1314	117241 122504
1996	1812	4589	2068	1800	0	121	10716	11644	11268	4397	0	1849	115960 122265
1997	1812	4339	2068	1800	0	127	10698	11661	11270	4397	0	1945	115723 122443
1998	1812	4339	2068	1800	0	126	10687	11666	11271	4397	0	1932	115621 122495
1999	1812	4339	2068	1800	0	126	10688	11672	11271	4397	0	1929	115642 122552
2000	1812	4039	2068	1800	0	190	10623	11662	11268	4397	0	2924	114024 122449

Table G-9
Net Sell, Low Penetration-Apartment

LOAD AND COST DATA

YEAR	PEAK LOAD	ANNUAL GEN	ANNUAL LOAD FACTOR	RESERV MARGIN	PROD COST	CAPITAL ADDITIONS	COST T&D	CUMUL UNIT	TOTAL COST	
	(MW)	(GWH)	(%)	(%)	ANNUAL (\$/G)	UNIT (\$/KWH)	GEN (\$/G)	(\$/G)	(\$/KWH)	ANNUAL UNIT (\$/G) (C/KWH)
1980	8051	38433	54.5	43.1	1469	3.82	0	0.0	3.21	3211 8.36
1981	8214	39040	54.3	39.8	1437	3.68	0	108.7	3.23	3209 8.22
1982	8351	39541	54.1	37.6	1392	3.52	0	91.9	3.28	3198 8.09
1983	8467	39945	53.8	35.3	1371	3.43	0	80.2	3.33	3211 8.04
1984	8547	40195	53.7	33.7	1296	3.23	0	60.1	3.34	3150 7.84
1985	8635	40459	53.5	32.3	1333	3.29	0	65.3	3.36	3200 7.91
1986	8664	40486	53.3	31.5	1360	3.36	0	27.1	3.37	3233 7.99
1987	8690	40513	53.2	35.4	1346	3.32	185	25.2	3.48	3266 8.06
1988	8766	40530	53.1	35.2	1465	3.62	0	18.0	3.49	3389 8.36
1989	8724	40475	53.0	34.5	1494	3.69	0	19.3	3.50	3422 8.46
1990	8730	40371	52.8	44.8	1356	3.36	852	11.6	3.98	3474 8.61
1991	8757	40449	52.7	44.3	1374	3.40	0	20.0	3.99	3497 8.65
1992	8775	40540	52.7	44.0	1391	3.43	0	12.3	3.99	3516 8.67
1993	8816	40700	52.7	43.3	1417	3.48	0	26.5	3.98	3549 8.72
1994	8844	40811	52.7	42.9	1438	3.52	0	18.1	3.98	3573 8.76
1995	8870	40927	52.7	42.5	1460	3.57	0	16.8	3.98	3599 8.79
1996	8885	41021	52.7	34.5	1444	3.52	0	8.4	3.94	3569 8.70
1997	8914	41148	52.7	31.2	1445	3.51	0	20.1	3.92	3570 8.68
1998	8934	41231	52.7	30.9	1448	3.51	0	12.9	3.92	3575 8.67
1999	8954	41334	52.7	30.7	1455	3.52	0	12.9	3.92	3585 8.67
2000	8965	41432	52.5	27.2	1465	3.54	0	7.1	3.90	3591 8.67

NOTE RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)					ENERGY OUTPUT (GIGAWATT-HOURS)					FUEL CONSUMPTION		
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	(\$/ BTU) RESID COAL
1980	1812	6945	0	1980	0	195	20631	0	12508	4400	0	2960	223085 0
1981	1812	6073	872	1950	0	359	17822	3502	12246	4400	0	5455	193807 38128
1982	1812	5738	1207	1950	0	365	15518	6346	12212	4400	0	5557	168633 68131
1983	1812	5277	1663	1920	0	482	13508	8863	12002	4400	0	7334	147683 94272
1984	1812	5277	1663	1890	0	229	12124	9149	11609	6400	0	3484	131394 96779
1985	1812	5277	1663	1890	0	257	12316	9189	11627	6400	0	3912	133667 97190
1986	1812	5277	1663	1860	0	278	12465	9223	11456	6400	0	4233	135439 97535
1987	1812	5277	1663	1830	400	133	12071	5965	11567	6400	932	2024	130253 105090
1988	1812	5277	1663	1830	400	262	13522	10403	11599	4397	1050	3982	146478 109549
1989	1812	5277	1663	1800	400	288	13651	10434	11410	4397	1072	4373	147936 109872
1990	1812	5277	2564	1800	400	69	10169	14030	11349	4397	920	1054	110443 146683
1991	1812	5277	2563	1800	400	73	10223	14051	11349	4397	923	1101	111034 146896
1992	1812	5277	2563	1800	400	73	10259	14064	11349	4397	925	1116	111393 147027
1993	1812	5277	2563	1800	400	82	10394	14127	11353	4397	930	1239	112898 147660
1994	1812	5277	2563	1800	400	85	10458	14162	11358	4397	936	1294	113608 148014
1995	1812	5277	2563	1800	400	89	10536	14198	11358	4397	947	1359	114475 148373
1996	1812	4589	2563	1800	400	130	10564	14212	11357	4397	942	1988	114558 148508
1997	1812	4339	2563	1800	400	150	10632	14261	11360	4397	963	2300	115238 149061
1998	1812	4339	2563	1800	400	141	10589	14389	11371	4397	975	2161	114673 150287
1999	1812	4339	2563	1800	400	143	10612	14415	11372	4397	979	2202	114909 150546
2000	1812	4039	2563	1800	400	232	10663	14427	11372	4397	1036	3572	114902 150661

Table G-10
Net Sell, Low Penetration-Office

LOAD AND COST DATA

YEAR	PEAK LOAD	ANNUAL GEN	ANNUAL LOAD FACTOR	RESERV MARGIN	PROD ANNUAL	COST UNIT	CAPITAL ADDITIONS GEN	COST T&D	CUMUL UNIT	TOTAL COST	
	(MW)	(GWH)	(%)	(%)	(E64)	(C/KWH)	(E64)	(E64)	(C/KWH)	ANNUAL (E64)	UNIT (C/KWH)
1980	8051	38457	54.5	43.1	1471	3.83	0	0.0	3.20	3212	8.35
1981	8206	39088	54.4	40.0	1440	3.68	0	102.2	3.23	3210	8.21
1982	8313	39579	54.4	38.2	1392	3.52	0	73.1	3.26	3192	8.07
1983	8367	39932	54.5	36.9	1364	3.42	0	42.6	3.30	3190	7.99
1984	8376	40177	54.8	36.4	1287	3.21	0	15.4	3.29	3117	7.76
1985	8394	40430	55.0	36.1	1316	3.26	0	20.6	3.28	3150	7.79
1986	8352	40454	55.3	36.5	1335	3.30	0	9.5	3.28	3172	7.84
1987	8312	40487	55.6	41.6	1326	3.28	185	8.2	3.38	3205	7.92
1988	8256	40495	56.0	42.5	1438	3.55	0	10.4	3.39	3319	8.20
1989	8221	40457	56.2	42.8	1455	3.60	0	7.0	3.39	3338	8.25
1990	8170	40359	56.4	52.2	1341	3.32	663	6.8	3.77	3371	8.35
1991	8164	40394	56.5	52.3	1356	3.36	0	3.8	3.77	3387	8.39
1992	8164	40462	56.6	52.3	1374	3.40	0	2.6	3.76	3406	8.42
1993	8205	40623	56.5	51.6	1398	3.44	0	26.5	3.76	3436	8.46
1994	8233	40734	56.5	51.1	1419	3.48	0	18.1	3.76	3460	8.50
1995	8259	40850	56.5	50.6	1441	3.53	0	16.8	3.76	3486	8.53
1996	8272	40943	56.5	42.0	1426	3.48	0	8.4	3.72	3457	8.44
1997	8303	41071	56.5	38.5	1426	3.47	0	20.1	3.70	3457	8.42
1998	8323	41154	56.4	38.2	1436	3.49	0	12.9	3.70	3469	8.43
1999	8343	41256	56.5	37.8	1447	3.51	0	12.9	3.70	3484	8.44
2000	8354	41355	56.5	34.1	1445	3.49	0	7.1	3.68	3476	8.41

NOTE RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)					ENERGY OUTPUT (GIGAWATT-HOURS)					FUEL CONSUMPTION (E9 BTU)		
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	RESID COAL
1980	1812	6945	0	1980	0	195	20659	0	12510	4400	0	2970	223391
1981	1812	6073	872	1950	0	359	17868	3507	12249	4400	0	5463	194300
1982	1812	5738	1207	1950	0	341	15548	6365	12218	4400	0	5197	168945
1983	1812	5277	1668	1920	0	433	13482	8907	12015	4400	0	6584	147276
1984	1812	5277	1668	1890	0	189	12027	9226	11661	6400	0	2868	130171
1985	1812	5277	1668	1890	0	196	12139	9287	11681	6400	0	2982	131420
1986	1812	5277	1668	1860	0	195	12221	9338	11509	6400	0	2966	132314
1987	1812	5277	1668	1830	400	86	11841	9999	11585	6400	780	1301	127627
1988	1812	5277	1668	1830	400	154	13338	10414	11611	4397	886	2334	143902
1989	1812	5277	1668	1800	400	152	13359	10426	11421	4397	877	2314	144139
1990	1812	5277	2368	1800	400	38	10262	13470	11392	4397	775	576	111275
1991	1812	5277	2368	1800	400	38	10284	13485	11393	4397	770	577	111503
1992	1812	5277	2368	1800	400	39	10345	13489	11392	4397	763	590	112130
1993	1812	5277	2368	1800	400	42	10467	13534	11395	4397	759	643	113430
1994	1812	5277	2368	1800	400	45	10541	13558	11396	4397	757	677	114223
1995	1812	5277	2368	1800	400	47	10626	13583	11397	4397	755	719	115135
1996	1812	4529	2368	1800	400	73	10690	13591	11396	4397	747	1116	115701
1997	1812	4339	2368	1800	400	82	10770	13625	11398	4397	749	1254	116535
1998	1812	4339	2368	1800	400	85	10825	13643	11399	4397	754	1297	117122
1999	1812	4339	2368	1800	400	89	10909	13664	11400	4397	759	1367	118021
2000	1812	4039	2368	1800	400	141	10849	13769	11405	4397	823	2165	116555

Table G-11
Net Sell, High Penetration-Apartment

LOAD AND COST DATA

YEAR	PEAK LOAD	ANNUAL GEN	ANNUAL LOAD FACTOR	RESERV MARGIN	PROD ANNUAL	COST UNIT	CAPITAL ADDITIONS GEN	COST T&D	CUMUL UNIT	TOTAL COST	
	(MW)	(GWH)	(%)	(%)	(EGJ)	(C/KWH)	(EGJ)	(L\$)	(C/KWH)	ANNUAL (EGJ)	UNIT (C/KWH)
1980	8051	38433	54.5	43.1	1469	3.82	0	0.0	3.21	3211	8.36
1981	8205	38970	54.2	40.0	1434	3.68	0	104.8	3.24	3205	8.22
1982	8333	39400	54.0	37.8	1385	3.52	0	88.6	3.29	3189	8.10
1983	8440	39735	53.7	35.7	1359	3.42	0	76.3	3.34	3197	8.05
1984	8512	39920	53.5	34.2	1283	3.22	0	56.8	3.36	3153	7.85
1985	8583	40637	53.3	33.1	1308	3.27	0	58.1	3.38	3171	7.92
1986	8595	39930	53.0	32.6	1330	3.33	0	19.9	3.40	3197	8.01
1987	8603	39018	52.8	36.8	1308	3.29	185	18.6	3.52	3220	8.09
1988	8601	39695	52.7	36.8	1417	3.57	0	12.2	3.54	3332	8.39
1989	8606	39534	52.4	36.4	1434	3.63	0	13.5	3.56	3352	8.48
1990	8604	39360	52.2	44.5	1329	3.38	663	9.6	3.95	3395	8.63
1991	8601	39199	52.0	44.6	1335	3.41	0	9.0	3.97	3403	8.68
1992	8597	39114	51.9	44.7	1344	3.44	0	6.4	3.99	3413	8.73
1993	8624	39170	51.8	44.2	1361	3.48	0	21.3	3.99	3435	8.77
1994	8635	39140	51.7	44.0	1374	3.51	0	11.0	4.00	3450	8.82
1995	8652	39186	51.7	43.7	1391	3.55	0	12.9	4.00	3470	8.86
1996	8665	39280	51.7	35.6	1375	3.50	0	8.4	3.96	3441	8.76
1997	8696	39407	51.7	32.2	1375	3.49	0	20.1	3.95	3440	8.73
1998	8716	39441	51.7	31.9	1385	3.51	0	12.9	3.94	3452	8.74
1999	8736	39593	51.7	31.6	1395	3.53	0	12.9	3.94	3466	8.75
2000	8747	39692	51.8	28.0	1402	3.53	0	7.1	3.92	3467	8.74

NOTE RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)				ENERGY OUTPUT (GIGAWATT-HOURS)						FUEL CONSUMPTION		
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	(GJ BTU) RESID COAL
1980	1812	6945	0	1980	0	195	20631	0	12508	4400	0	2560	223085 0
1981	1812	6073	872	1950	0	354	17776	3499	12244	4400	0	5383	193286 38096
1982	1812	5738	1207	1950	0	356	15418	6328	12206	4400	0	5415	167500 67943
1983	1812	5277	1668	1920	0	455	13378	8828	11993	4400	0	6528	146226 93916
1984	1812	5277	1668	1890	0	216	11957	9095	11583	6400	0	3286	129545 96230
1985	1812	5277	1668	1890	0	230	12019	9104	11588	6400	0	3507	130275 96316
1986	1812	5277	1668	1860	0	247	12112	9111	11598	6400	0	3759	131379 96390
1987	1812	5277	1668	1830	400	113	11560	9815	11547	6400	921	1718	124745 103571
1988	1812	5277	1668	1830	400	204	12923	10263	11583	4397	1000	3111	139995 108117
1989	1812	5277	1668	1800	400	209	12934	10272	11393	4397	1010	3181	140173 108214
1990	1812	5277	2368	1800	400	72	12196	13063	11330	4397	925	1093	110605 136234
1991	1812	5277	2368	1800	400	70	12110	12539	11322	4397	929	1068	109664 135581
1992	1812	5277	2368	1800	400	68	12071	12866	11315	4397	927	1038	109240 135052
1993	1812	5277	2368	1800	400	72	12103	12907	11317	4397	934	1096	109600 135256
1994	1812	5277	2368	1800	400	73	12082	12887	11313	4397	938	1102	109384 135057
1995	1812	5277	2368	1800	400	75	12119	12901	11314	4397	940	1137	109790 135196
1996	1812	4589	2368	1800	400	112	10159	12915	11314	4397	935	1713	110015 135340
1997	1812	4339	2368	1800	400	123	10223	12563	11319	4397	941	1881	110684 135825
1998	1812	4339	2368	1800	400	128	10273	12588	11321	4397	942	1971	111227 136081
1999	1812	4339	2368	1800	400	134	10341	13022	11323	4397	944	2057	111959 136421
2000	1812	4035	2368	1800	400	222	10349	13035	11323	4397	1010	3419	111396 136549

Table G-12
Net Sell, High Penetration-Office

LOAD AND COST DATA

YEAR	PEAK LOAD (MW)	ANNUAL GEN (GWH)	ANNUAL LOAD FACTOR (%)	RESERV MARGIN (%)	PROD COST		CAPITAL COST		CUMUL UNIT (C/KWH)	TOTAL COST	
					ANNUAL (E6\$)	UNIT (C/KWH)	GEN (E6\$)	TRD (E6\$)		ANNUAL (E6\$)	UNIT (C/KWH)
1980	8051	38457	54.5	43.1	1471	3.83	0	0.0	3.20	3212	8.35
1981	8202	39077	54.4	40.1	1439	3.68	0	99.6	3.22	3209	8.21
1982	8309	39569	54.4	38.2	1391	3.52	0	73.7	3.26	3192	8.07
1983	8363	39920	54.5	37.0	1364	3.42	0	42.0	3.30	3190	7.99
1984	8355	40121	54.6	36.8	1284	3.20	0	11.5	3.29	3112	7.76
1985	8326	40248	55.2	37.2	1303	3.24	0	13.3	3.28	3134	7.79
1986	8247	40168	55.6	38.2	1315	3.22	0	12.2	3.30	3149	7.84
1987	8160	40078	56.1	39.3	1326	3.31	0	13.5	3.31	3163	7.89
1988	8080	40017	56.5	40.7	1416	3.54	0	10.6	3.32	3255	8.14
1989	8002	39865	56.9	41.7	1431	3.59	0	11.5	3.34	3273	8.21
1990	7912	39664	57.2	48.3	1360	3.43	378	10.8	3.57	3287	8.29
1991	7904	39527	57.1	48.5	1368	3.46	0	-30.1	3.57	3285	8.32
1992	7891	39379	57.0	48.7	1374	3.49	0	-33.3	3.56	3288	8.35
1993	7894	39254	56.8	48.7	1382	3.52	0	-31.5	3.56	3285	8.38
1994	7892	39137	56.6	48.7	1390	3.55	0	-0.0	3.57	3297	8.42
1995	7887	39014	56.5	48.8	1398	3.59	0	0.0	3.58	3305	8.47
1996	7873	38885	56.4	40.3	1370	3.52	0	0.0	3.55	3261	8.39
1997	7887	38893	56.3	36.9	1363	3.51	0	9.1	3.54	3251	8.36
1998	7891	38861	56.2	36.9	1366	3.52	0	2.6	3.55	3254	8.37
1999	7896	38850	56.2	36.8	1370	3.53	0	3.2	3.55	3259	8.39
2000	7892	38835	56.2	33.0	1365	3.52	0	-0.0	3.53	3247	8.36

*NOTE RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW.

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)				ENERGY OUTPUT (GIGAWATT-HOURS)					FUEL CONSUMPTION			
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	(E9 BTU) RESID COAL
1980	1812	6945	0	1980	0	195	20659	0	12510	4400	0	2970	223391 0
1981	1812	6073	872	1950	0	357	17866	3507	12250	4400	0	5428	194267 38180
1982	1812	5730	1207	1950	0	340	15544	6366	12219	4400	0	5173	168886 68335
1983	1812	5277	1668	1920	0	430	13481	8907	12015	4400	0	6547	147254 94730
1984	1812	5277	1668	1890	0	184	11983	9221	11659	6400	0	2792	129669 97512
1985	1812	5277	1668	1890	0	180	11975	9260	11664	6400	0	2736	129576 97911
1986	1812	5277	1668	1860	0	170	11967	9294	11482	6400	0	2590	129469 98259
1987	1812	5277	1668	1830	0	164	11942	9318	11299	6400	0	2496	129144 98498
1988	1812	5277	1668	1830	0	256	12940	9692	11470	4397	0	3890	140414 104340
1989	1812	5277	1668	1800	0	229	12971	9943	11291	4397	0	3480	140724 104853
1990	1812	5277	2068	1800	0	98	11205	11628	11263	4397	0	1487	121313 122114
1991	1812	5277	2068	1800	0	100	11099	11623	11263	4397	0	1516	120238 122056
1992	1812	5277	2068	1800	0	92	11000	11603	11260	4397	0	1393	119167 121858
1993	1812	5277	2068	1800	0	91	10897	11615	11262	4397	0	1373	118052 121978
1994	1812	5277	2068	1800	0	91	10801	11613	11262	4397	0	1301	117018 121954
1995	1812	5277	2068	1800	0	86	10713	11604	11261	4397	0	1301	116097 121865
1996	1812	4589	2068	1800	0	121	10603	11578	11257	4397	0	1241	114716 121594
1997	1812	4339	2068	1800	0	126	10591	11599	11260	4397	0	1939	114562 121806
1998	1812	4339	2068	1800	0	125	10567	11596	11259	4397	0	1923	114326 121783
1999	1812	4339	2068	1800	0	125	10565	11601	11259	4397	0	1922	114311 121830
2000	1812	4039	2068	1800	0	188	10498	11589	11257	4397	0	2687	112695 121712

Table G-13
Net Buy, Low Penetration-Office

LOAD AND COST DATA

YEAR	PEAK LOAD	ANNUAL PEU	ANNUAL LOAD FACTOR	RESERV MARGIN	PROD	COST	CAPITAL		COST	TOTAL COST	
	(MW)	(CWH)	(%)	(%)	ANNUAL (EGS)	UNIT (C/KWH)	ADDITIONS GEN (EGS)	TRD (EGS)	CUMUL UNIT (C/KWH)	ANNUAL (EGS)	UNIT (C/KWH)
1980	8051	38458	54.5	43.1	1471	3.83	0	0.0	3.20	3213	8.35
1981	8209	39095	54.4	39.9	1441	3.69	0	102.2	3.22	3211	8.21
1982	8322	39599	54.3	38.0	1392	3.52	0	73.1	3.26	3193	8.06
1983	8388	39977	54.4	36.6	1366	3.42	0	42.7	3.29	3193	7.99
1984	8412	40254	54.6	35.8	1291	3.21	0	15.5	3.28	3120	7.75
1985	8444	40538	54.8	35.3	1322	3.26	0	20.7	3.27	3156	7.79
1986	8418	40593	55.0	35.4	1343	3.31	0	.3	3.26	3177	7.83
1987	8392	40658	55.3	40.2	1335	3.29	185	.3	3.36	3210	7.90
1988	8351	40697	55.6	40.9	1448	3.56	0	-.3	3.35	3323	8.17
1989	8327	40684	55.8	41.0	1472	3.62	0	0.0	3.36	3347	8.23
1990	8289	40614	55.9	52.5	1335	3.29	852	.5	3.82	3398	8.37
1991	8289	40662	56.0	52.5	1344	3.31	0	0.0	3.82	3406	8.38
1992	8293	40737	56.1	52.4	1361	3.34	0	2.6	3.81	3424	8.41
1993	8334	40898	56.0	51.6	1383	3.38	0	26.5	3.81	3452	8.44
1994	8362	41008	56.0	51.1	1403	3.42	0	18.1	3.81	3476	8.48
1995	8388	41124	56.0	50.7	1424	3.46	0	16.8	3.81	3501	8.51
1996	8401	41217	56.0	42.2	1408	3.42	0	8.4	3.77	3472	8.42
1997	8432	41345	56.0	38.7	1408	3.41	0	20.1	3.76	3471	8.40
1998	8452	41428	56.0	38.4	1417	3.42	0	12.9	3.75	3482	8.41
1999	8472	41530	56.0	38.1	1428	3.44	0	12.9	3.75	3496	8.42
2000	8483	41630	56.0	34.4	1432	3.44	0	7.1	3.73	3495	8.40

NOTE RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)					ENERGY OUTPUT (GIGAWATT-HOURS)					FUEL CONSUMPTION		
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	(E9 BTU) RESID COAL
1980	1812	6945	0	1980	0	196	20661	0	12510	4400	0	2971	223403 0
1981	1812	6073	872	1950	0	361	17882	3508	12249	4400	0	5480	194441 38185
1982	1812	5738	1207	1950	0	342	15557	6367	12219	4400	0	5201	169048 68340
1983	1812	5277	1668	1920	0	437	13510	8911	12017	4400	0	6645	147584 94765
1984	1812	5277	1668	1890	0	192	12073	9236	11663	6400	0	2914	130677 97669
1985	1812	5277	1668	1890	0	201	12215	9365	11690	6400	0	3052	132241 98373
1986	1812	5277	1668	1860	0	205	12318	9361	11517	6400	0	3108	133362 98942
1987	1812	5277	1668	1830	400	90	11567	10015	11587	6400	759	1361	129012 105609
1988	1812	5277	1668	1830	400	161	13478	10433	11612	4397	911	2449	145412 109861
1989	1812	5277	1668	1800	400	161	13600	10455	11423	4397	908	2444	146722 110080
1990	1812	5277	2568	1800	400	36	9881	14119	11375	4397	777	547	107295 147585
1991	1812	5277	2568	1800	400	29	9777	14248	11285	4397	789	445	106183 148885
1992	1812	5277	2568	1800	400	31	9838	14254	11283	4397	784	472	106802 148943
1993	1812	5277	2568	1800	400	33	9833	14313	11286	4397	788	498	107824 149540
1994	1812	5277	2568	1800	400	34	10001	14351	11288	4397	790	526	108554 149923
1995	1812	5277	2568	1800	400	37	10083	14396	11289	4397	792	562	109430 150368
1996	1812	4589	2568	1800	400	58	10151	14405	11288	4397	786	884	110056 150464
1997	1812	4339	2568	1800	400	64	10221	14442	11291	4397	782	979	110805 150833
1998	1812	4339	2568	1800	400	67	10271	14461	11292	4397	779	1024	111328 151022
1999	1812	4339	2568	1800	400	70	10351	14484	11293	4397	775	1082	112167 151255
2000	1812	4039	2568	1800	400	118	10610	14498	11292	4397	820	1808	112078 151396

Table G-14
Net Buy, High Penetration-Office
LOAD AND COST DATA

YEAR	PEAK LOAD	ANNUAL GEN	ANNUAL LOAD FACTOR	RESERV MARGIN	PROD COST		CAPITAL ADDITIONS		COST CUMUL	TOTAL COST	
	(MW)	(GWH)	(%)	(%)	ANNUAL (€63)	UNIT (C/KWH)	GEN (€63)	T&D (€63)	UNIT (C/KWH)	ANNUAL (€63)	UNIT (C/KWH)
1980	8051	38458	54.5	43.1	1471	3.83	0	0.0	3.20	3213	8.35
1981	8205	39025	54.4	40.0	1440	3.69	0	99.7	3.22	3210	8.21
1982	8319	39588	54.3	38.1	1392	3.52	0	73.8	3.26	3192	8.07
1983	8384	39966	54.4	36.7	1366	3.42	0	42.1	3.29	3191	7.99
1984	8394	40204	54.7	36.1	1288	3.21	0	6.5	3.28	3115	7.75
1985	8387	40376	55.0	36.2	1310	3.25	0	.3	3.26	3137	7.77
1986	8327	40340	55.5	36.9	1324	3.28	0	0.0	3.27	3151	7.81
1987	8261	40294	55.7	37.6	1339	3.32	0	0.0	3.27	3166	7.86
1988	8200	40274	56.1	38.6	1439	3.57	0	.5	3.27	3266	8.11
1989	8140	40159	56.3	39.3	1444	3.60	0	0.0	3.28	3272	8.15
1990	8068	39997	56.6	45.5	1373	3.43	378	.3	3.50	3284	8.21
1991	8013	39892	56.6	46.5	1381	3.46	0	0.0	3.51	3292	8.25
1992	7946	39774	57.1	47.7	1391	3.50	0	0.0	3.52	3302	8.30
1993	7896	39682	57.4	48.6	1401	3.53	0	0.0	3.53	3312	8.35
1994	7892	39590	57.3	48.7	1409	3.56	0	-1.0	3.54	3320	8.39
1995	7887	39493	57.2	48.8	1418	3.59	0	0.0	3.55	3329	8.43
1996	7873	39394	57.1	40.3	1390	3.53	0	0.0	3.52	3286	8.34
1997	7887	39411	57.0	36.9	1384	3.51	0	9.1	3.51	3275	8.31
1998	7891	39392	57.0	36.9	1386	3.52	0	2.6	3.51	3279	8.32
1999	7896	39394	57.0	36.8	1391	3.53	0	3.2	3.51	3284	8.34
2000	7892	39392	57.0	33.0	1386	3.52	0	-0.0	3.49	3273	8.31

NOTE RESERVE MARGIN INCLUDES FIRM HYDRO CAPACITY OF 780 MW

CAPACITY, GENERATION, AND FUEL USE DATA

YEAR	INSTALLED CAPACITY (MEGAWATTS)					ENERGY OUTPUT (GIGAWATT-HOURS)					FUEL CONSUMPTION		
	COMB TURB	OIL- STEAM	COAL	NUCL	PUMP STRG	COMB TURB	OIL- STEAM	COAL	NUCL	HYDRO	PUMP STRG	DIST	(€9 BTU) RESID COAL
1980	1912	6945	0	1980	0	196	20661	0	12510	4400	0	2971	223403 0
1981	1812	6073	872	1950	0	358	17872	3507	12250	4400	0	5438	194341 38183
1982	1812	5738	1207	1950	0	341	15555	6367	12219	4400	0	5195	169013 68339
1983	1812	5277	1668	1920	0	434	13503	8910	12017	4400	0	6603	147502 94760
1984	1812	5277	1668	1890	0	187	12041	9236	11666	6400	0	2843	130301 97660
1985	1812	5277	1668	1890	0	185	12072	9283	11674	6400	0	2817	130622 98147
1986	1812	5277	1668	1860	0	179	12079	9321	11491	6400	0	2716	130667 98537
1987	1812	5277	1668	1830	0	170	12108	9366	11313	6400	0	2585	130940 98992
1988	1812	5277	1668	1830	0	279	13218	9831	11464	4397	0	4242	144073 103728
1989	1812	5277	1668	1800	0	253	13125	9944	11288	4397	0	3851	142435 104863
1990	1812	5277	2068	1800	0	115	11374	11635	11257	4397	0	1749	123129 122191
1991	1812	5277	2068	1800	0	109	11281	11642	11259	4397	0	1646	122146 122259
1992	1812	5277	2068	1800	0	102	11225	11628	11257	4397	0	1552	121514 122117
1993	1812	5277	2068	1800	0	103	11143	11646	11261	4397	0	1558	120626 122296
1994	1812	5277	2068	1800	0	97	11052	11643	11260	4397	0	1464	119667 122269
1995	1812	5277	2068	1800	0	91	10972	11643	11261	4397	0	1388	118801 122265
1996	1812	4589	2068	1800	0	128	10862	11617	11258	4397	0	1949	117435 122004
1997	1812	4339	2068	1800	0	134	10848	11645	11261	4397	0	2053	117226 122289
1998	1812	4339	2068	1800	0	133	10824	11648	11261	4397	0	2036	116984 122312
1999	1812	4339	2068	1800	0	133	10829	11658	11262	4397	0	2033	117045 122415
2000	1812	4039	2068	1800	0	200	10757	11649	11260	4397	0	3079	115343 122320