Long Run Electricity Pricing in a Deregulated Competitive Electricity Market

by

Eugene Vamos

B.S. Industrial Engineering
Stanford University, 1991

Submitted to the
Department of Civil and Environmental Engineering
in Partial Fulfillment of the Requirements
for the Degree of

Master of Science
in Technology and Policy
at the

Massachusetts Institute of Technology

May 1995

Signature of Author______________________________
Department of Civil and Environmental Engineering
May 12, 1995

Certified by______________________________
A. Denny Ellerman
Executive Director, Center for Energy and Environmental Policy Research
Senior Lecturer, Sloan School of Management
Thesis Supervisor

Certified by______________________________
Richard de Neufville
Chairman, Technology and Policy Program
Professor, Department of Civil and Environmental Engineering

Accepted by______________________________
Joseph M. Sussman
Chairman, Departmental Committee on Graduate Studies

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Abstract

As the electric utility industry faces deregulation, direct access to electricity customers will foster competition among present public utilities and new suppliers of electricity. The prospect of competition under retail wheeling is expected to lower prices by setting up a competitive environment for the sale and purchase of electricity. Under this competitive market assumption, prices will decrease as suppliers with efficient least cost generating technologies gain access to increasing numbers of electricity consumers.

This thesis quantifies long run prices of electricity in a deregulated, competitive market. It disaggregates the market into various customer groups and establishes prices based on consumer load profiles derived from utility databases. The magnitude of potential price reduction is assessed given various competitive advantage techniques which suppliers might develop. Competitive advantage techniques are assessed to determine if and by how much electricity prices can be lowered. Two techniques are examined: optimal Baseload/Peaking capacity allocation and load aggregation.

Thesis Supervisor: A. Denny Ellerman

Title: Senior Lecturer, Sloan School of Management

Acknowlegements

The thesis in front of you is the culmination of an academic, scientific and intellectual journey that started at Stanford University, wandered through the Jet Propulsion Laboratory, passed by the Massachusetts Institute of Technology, detoured around New England Electric System and finally concluding at Arthur D. Little. I want to thank all the people that I encountered in the course of this voyage as it is their ideas, knowledge and experiences that are laid out in these pages. First and foremost, I want to thank my advisor, Dr. Denny Ellerman for the countless hours that he invested in my thesis, talking with me, reading my drafts, and making me aware that good points stand out better when they are concise. A lot can be learned for a good advisor, and I have learned much more from a great one. I want to thank my family, Mamá, Papá, and Pepe, for all the support I got 3,000 miles away from home. It has been a hard journey but one that will be well worth it for the family in the future.

I want to thank the people from NEES; my view of electric utilities will never be the same after a year as an intern. Thanks to Jon, Kevin, Ann, Phil, Sue, Bob, Dorothy, and especially Martin for all those deregulation and non-deregulation talks that we had. I want to thank the Fuel Cell Team at JPL for getting me started in this energy/electricity thinking almost four years ago. It has definitely been a path less traveled, but one that has been full of surprises and rewarding experiences. I am indebted to Rao, Narayanan, Harvey, and Jerry for their support. Our paths will cross again, I guarantee that.

Last, but not least, I want to thank all the friends that I have met in Boston these past two years. The crew at Ashdown Hall has been a great social support; many friendships have been made: Nicholas, Rama, Sang, Andy, Tom, et al. No words can convey my appreciation for my roommate Scott. From Martha's Vineyard to Slingshot to Bertucci's to Lexington to the Study Room, it has been an incredible two years of friendship. To the Stanford-At-Boston group; John, Susan, Ed and Nathaniel, thanks for being there and may Fortune smile in your future endeavors.

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Chapter 1: Introduction

Problem Statement

Regulated vertically integrated utilities have provided the main bulk of electricity service to American consumers for the last 70 years. The traditional regulatory compact for electricity service grants a utility the exclusive right to supply electricity to customers in a specified geographical area. The compact also maintains the utility's financial integrity by allowing it to recover reasonably incurred expenses and to earn a fair return on its capital investment. States regulate these utilities to ensure that they provide safe, reliable and reasonably priced service to all consumers within the franchise area, subject to the condition that they do not unduly discriminate against any consumer.[1] However, there is a growing consensus that this regulatory compact has failed to provide low cost electricity. Policy makers have arrived at the conclusion that cost-of-service regulation has been a major cause of high electricity costs. It is also understood that this regulatory frame work is fundamentally at odds with and ill suited to bring about a reduction of these costs. The deregulation of utilities and the introduction of competition to the electricity service market is seen as an alternate market framework to exert downward pressure on the prices of residential, industrial and commercial consumers.

A considerable amount of research and analysis has been carried out examining the manner and the timing of the deregulation of electric markets and the introduction of competition. Various market models have been developed; the manner in which these competitive models are implemented will affect how electricity goods are priced. The industry will go through volatile and uncertain price paths in the short run as soon as competition is introduced and transition adjustments are made. These prices will begin to stabilize in the medium run as firms enter and exit the market, moving towards competitive equilibrium positions. In theory, over the long run all remnants of the regulatory compact will be eliminated, and the electric market will function in a perfectly competitive manner.

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[1]California Public Utilities Commission. Order Instituting Rulemaking on the Commisions's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation R. 94-04-031, R. 94-040-032. 20 April 1994: 50.

As new capacity is required due to plant retirements and new demand growth, electricity prices will move towards a set of long run prices for electricity based on the cost of service set by new low cost electricity generating plants.

Because of electricity's homogeneous characteristics, it has been perceived as a product that will be transacted as a commodity good with a single price attached to it.[2] This thinking implies that the long run price of electric service converges upon to a single value and that all consumers will receive similar types of electricity commodity service. However, this view does not take into consideration that the electricity market place will fragment as soon as individual customers gain the ability to chose providers, and providers gain the ability to offer consumer tailored services. Given the large diversity of consumption patterns and requirements by the multitude of residential, industrial and commercial establishments, the perception that *"electric services can only involve a uniform standardized service or commodity is fundamentally incorrect and can lead reform efforts down the wrong path."*[3]. Electric services will become a highly differentiated portfolio of products whose variation and costs are presently obscured by the manner utilities and rate regulation implicitly package and price electricity service.

Individual consumers in a deregulated marketplace will have the freedom to create their own custom bundle of electricity that might or might not reflect the current traditional full service provided by utilities. Competitors will find and deliver to customers more efficient ways to provide traditional needs but also will find new different services to meet consumer needs. A broader range of differentiated services will link and match the needs of different consumers with the product and services of competitive suppliers.[4] For present utilities and new market entrants, it will be important to understand how electricity will be sold and purchased at the retail level in order to develop strategic plans for success in a competitive market place.

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[2]Edison Electric Institute. Electricity Futures: Potential Impact and Utilties. (Edison Electric Institute, Finance, Regulation and Power Supply Policy Group, 1995) Prepared by Susan Dudley, Economists Incorporated.

[3]California Energy Commission. Fourth Round Opening Comments on Direct Access and Customer Choice Role, Structure and Efficacy. Restructuring OIR Proceedings R. 94-04-031, R. 94-040-032. (1994):1.

[4]California Energy Commission:1.

Thesis Outline

This thesis examines this link between electricity product and electricity consumer. It builds a model to characterize competitive supply and demand and to calculate long run electricity prices in a deregulated competitive market. This thesis seeks to answer the following questions: What factors influence the long run price of electricity in a deregulated market? Do different customers have different consumption needs, and how do those consumption needs affect the price of electricity? How do electricity suppliers react in a competitive marketplace, and what kind of competitive advantages can they develop to supply electricity at a lower cost? Long run costs in a competitive environment will be directly based on the dynamics of consumer needs and the methods of electricity supply. Costs will be a function of how well suppliers can take advantage of customer consumption patterns to deliver competitively priced electricity.

Chapter One introduces this customer/supplier model and provides a general framework for the flow of the thesis. In **Chapter Two**, a methodology is established to quantify the *electricity consumer* . In a deregulated environment, all customers will gain individual choice to select their providers of electricity. This section of the thesis tries to approximate how this present monolithic consumer will splinter into smaller consumption units. Groups are separated by industrial and commercial activities, and their consumption patterns are quantified based on time dependent electricity demand data. A generalized figure of merit is developed to characterize load consumption by customer type.

Chapter Three brings together the framework of the electricity consumer and the electricity product and calculates the cost of electricity service for the various customer groups identified in Chapter Two. A financial model is constructed to determine the economics of providing the electricity product to segmented customers. Using a tariff based on capacity and energy consumption, cost of service estimates are calculated for various customer groups. Although the two part tariff methodology has been used extensively to calculate cost of service by utilities, the methodology is utilized here to arrive at stand alone calculations representing average full costs of service. This characterization approximates the manner a supplier might approach a customer in a bilateral trade market.

In a competitive market, the supplier of goods strives to be the lowest cost provider by developing supply competitive advantages. The level of price competition in a market can be assessed by determining the possibility and magnitude of how competitive advantage techniques can lower the price of electricity. **Chapter Four** analyses such a competitive advantage technique to get a general sense of the range in cost savings. A capacity construction strategy is proposed based on optimal baseload and peaking capacity allocation for various disaggregated consumer loads.

In **Chapter Five**, an additional methodology is proposed to further measure the extent which competitive advantages can lower the cost of electricity. Potential economics of scope are examined by having an electricity supplier aggregate load consumption for two or more customers. Given the multitude of load profiles associated with customers, there are consumer loads that can complement each other. A winter peaking consumer might complement a summer peaking one; a night peaking consumer could complement a day peaking consumer. Complimentary load potential is quantified and complementing customers are identified. Various customer combinations are examined to establish how these attempts can affect the price of electricity. **Chapter Six** summarizes the research in the thesis.

Chapter 2: Customer Quantification

As the market moves towards a competitive level, consumer data that describes electricity consumption become essential to gather. Who these customers are, how much they consume, and when they consume electricity are questions that players in the market will have to answer and understand. In this chapter, the competitive electricity market is defined, potential customers segments are identified, and their consumption load characteristics are examined. Long Run electricity prices will not only depend on the generation costs but also on customer requirements and needs. These needs can be approximated by load consumption patterns.

The Market Place

In the present electricity supply paradigm, the retail electricity market has two players: the utility and the consumer. The utility has an obligation to serve the retail consumer, and the consumer has to be served by the utility. In a deregulated, competitive market, consumers will be able to seek out electricity services from other suppliers. Many other players will enter the market, such as brokers, commodity exchanges, pool establishments, load aggregators, etc., forming a complicated web of electricity supply and demand.

The model formulated in this thesis simplifies the potential market into three players: the new suppliers, the established utility and the electricity consumers:

- New Suppliers are defined as new and old establishments that will enter the electricity market to serve customers presently in the service territory of established utilities. Present Independent Power Producers, entrepreneurs, Cogenerators and other utilities can be thought as potential new suppliers.
- The Established Utility will be referred as the company which at one point had the obligation to serve a certain geographical area of consumers.
- The third player in the market are the different users of electricity that will have the choice to remain with the established utility or seek out service from a new supplier.

The thousands of different users are grouped in this model into 23 representative categories called customer groups or segments.

The model assumes that a deregulated competitive market has free entry and exit, and no institutional barriers to entry. It is assumed that transmission and distribution constraints are not present and that delivery conditions from any supplier to any consumer are identical. There is no market power and each firm faces a horizontal demand line. It is assumed that all firms are in equilibrium and that there is a full recovery of fixed and variable costs along with a predetermined return on investment. It is assumed that established utilities will not have the obligation to serve all customers and will have to price electricity based solely on market forces; No regulatory compact is assumed.

The Consumer

This long run pricing model is carried out within a proxy market. This proxy market is defined as all industrial and commercial customers from three New England electric utilities: New England Electric System (NEES)[5], Boston Edison Company (BECO)[6] and Northeastern Utilities (NU).[7] Using information provided by IRP filings, twenty three customer groups of industrial and commercial entities are identified. Energy needs for these 23 customer groups from the three utilities are based on 1995 projected figures (Appendix C). Industrial customers are grouped by SIC industry type to capture electricity consumption patterns that are basic to the industry. Commercial customers are grouped together by building type to reflect consumption patterns that are representative of the building's function. The various customer groups represented in this model are shown in Table 1. General descriptions of these consumer groups can be found in Appendix G.

Table 1. Industrial and Commercial Groups Represented in Model

Industrial Groups		**Commercial Groups**	
Food	Primary Metal	Office	Health
Textile Mill	Fabricated Metal	Restaurant	Hotel
Paper	Industrial Machinery	Groceries	Miscellaneous
Printing	Electronic	Education	Warehouse
Chemicals	Transportation	Retail	
Rubber	Instruments		
Stone, Clay and Glass	Miscellaneous		

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[5]New England Electric System. Integrated Least Cost Resource Plan for the Fifteen Year Period 1994-2008

[6]Boston Edison Company Integrated Resource Management Initial Filing.(15 July 1994)

[7]Northeast Utilities. The Northeast Utilities System 1993 Forecast of Loads and Resources for 1993-2012.

Customer Identification

By disaggregating industrial and commercial customers into various subcategories, individual behavior profiles can be examined to provide individualized electricity consumption needs and requirements. Although the electricity that is consumed is identical, customers have differing electricity needs based on hourly, daily and seasonal fluctuations. These needs translate into unique demand patterns for each customer. Load requirements by customer segments can be analyzed, and usage profiles can be created. This information becomes critical in the electricity generating market as competitors attempt to serve customers by creating specialized bundles of energy and electricity products. This quantification is used to determine the consumption differentiation between each customer group and identifies customer service implications.

Description of NEES Load Shape Data Source

Time based consumption information is hard to access at the present time as utility energy billing to customers usually does not require this level of detail. Residential and commercial customers are usually charged electricity with a one part tariff that has a uniform rate per kilowatt-hour. Industrial customers are charged a two part tariff that keeps track of electricity consumption along with the maximum demand of the customer during a defined time period (e.g. twelve months) as measured in terms of kilowatts by a maximum demand meter. Three part tariffs tack on the cost of serving customers even if the customer does not use the service at all. Examples of customer costs are local connection facilities, metering equipment, billing, and accounting.[8]

To develop better peak capacity and energy forecast models, utilities have begun to pay closer attention to time specific single customer consumption and acquired the ability to meter them.[9] The New England Electric System has developed individual customer load profile information for close to 5000 industrial and commercial customers. Typical day load shapes was collected via NEES's load research program in the Massachusetts Electric and Naragansett Electric service areas. Information was gathered from July 1990 through June of 1991 through the installations of meters that record electrical usage at fifteen minute intervals for randomly selected, statistically representative groups of customers.[10] With this large amount of rich data, it is possible to examine closely the consumption patterns of

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[8]Bonbright, James. Principles of Public Utility Rates.(Arlington: Public Utilities Reports Inc, 1988) 401.
[9]NEES-IRP, Volume 1:The Demand Forecast, 6-1, 6-5.
[10]NEES-IRP, Volume 1:The Demand Forecast, 6-12,6-13.

individual customers. Unfortunately, NEES has only made public through their IRP filing aggregated groupings of load shape data.

Customer Profile Development

This consumer data is collected into nine commercial and fourteen industrial groups and presents weekday, weekend, and peak-day hourly profiles for a typical winter and summer. Raw consumption data for these customers is graphically presented in Appendix A. Days in the year are assigned the characteristics of these representative template loads in the following manner:

- Summer and Winter seasons are evenly split
- There are 52 weeks in the year, with 104 weekend days 52/Summer 52/Winter
- 5 peak days fall during the Summer and 5 peak days fall during the Winter
- The rest of the days are called Average Weekdays 126.5/Summer 126.5/Winter

To create a market that encompasses the customers of the three New England utilities in question, NU, NEES, BECO, energy needs by customer are added together. From IRP reports, the energy needs for a 1995-basecase year are identified for each of the three utilities. To form a market of customer groups, the respective energy requirements are added together for each customer group (Figure 1). With deregulation and open access, customers will not be tied to specific utilities; all groups will form part of a greater competitive market.

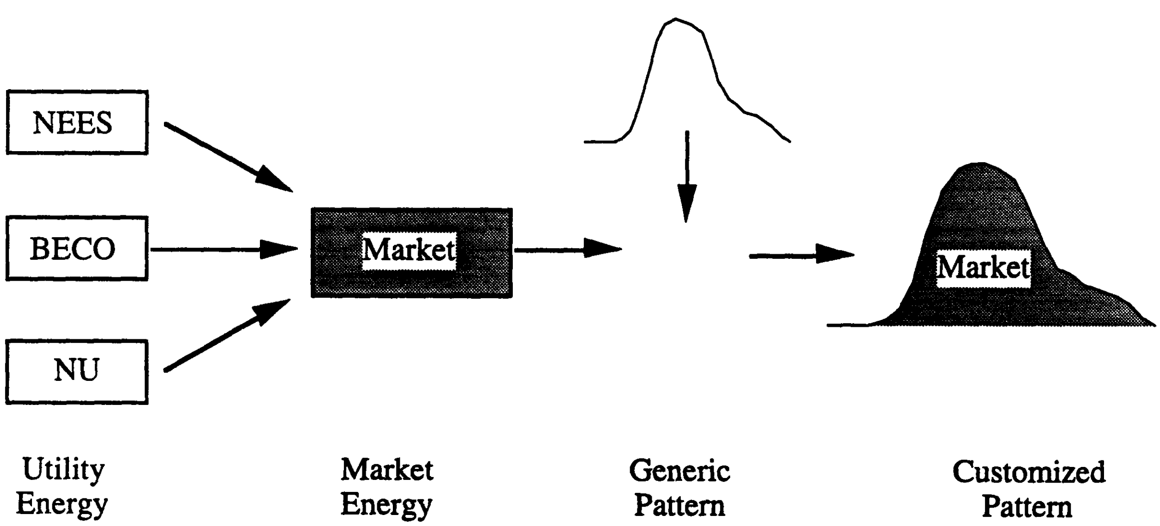


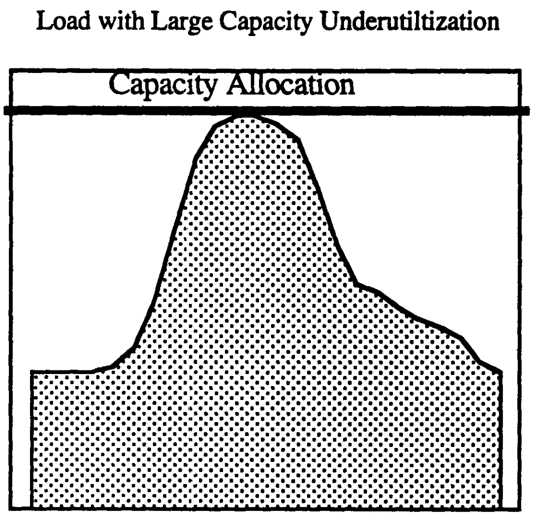
Figure 1. Customer Load Pattern Derivation

The load pattern templates derived from the NEES IRP are reshaped to reflect the energy requirements for the various New England market customer groups. In other words, the load patterns are scaled so that the integration under the load pattern curve reflects the total consumption energy needs for the entire market.

Load Factor Calculations

It is useful to quantify hourly, daily and seasonal consumption patterns for these distinct groups of customers to determine consumption variability. If most customers have similar consumption profiles, the service of electricity will be rather homogeneous across customer classes. If customer groups exhibit varied load consumption patterns, the market will have to respond and tailor services to a variety of needs and demands. The dynamic nature of the electricity market place will be determined by the amount of differentiated products that will required. Electricity suppliers will be competing with each other to provide the best *"value"* of electricity *"goods"* to electricity consumers. The nature of this *"value"* and the packaging of these *"goods"* is the key driver for a dynamic, low-price market place.

As the market dissolves from a single monolithic demand pattern to a multiple consumer scene, electricity suppliers will have to focus upon single consumers. These consumers will have unique demand patterns, and electricity suppliers will have to examine these consumer traits to provide service and set costs. It is important to come up with a figure of merit that describes the nature of customer usage. Not only can this consumption can be described by raw energy requirements (kWhr), but also by the manner this energy is consumed over time. Some customers require large amounts of electricity for only a few hours; others require electricity in a more even manner. If a supplier is to provide service to customers, one of the first factors to consider is the maximum amount of energy needed at any given time. This number determines how much capacity a certain plant needs to allocate to serve a customer. Having established the maximum capacity requirements for a given customer, how much of that capacity will be utilized in a certain period can be calculated. Customers with uneven loads will make supplier's plants remain idle for long periods of time (Figure 2). Customers with more even loads will enable the supplier to utilize its plant capacity more effectively (Figure 3).



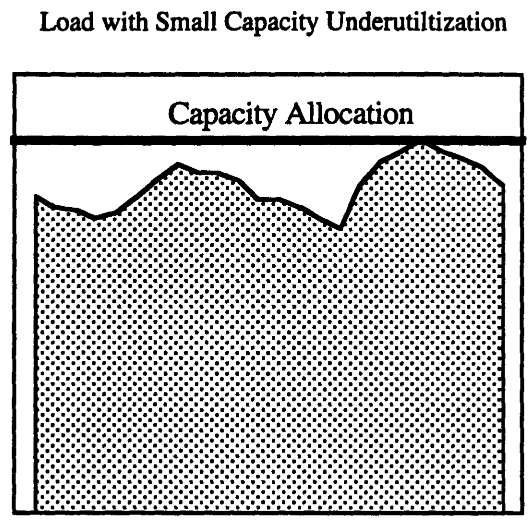


Figure 2. Generic Load With Large Capacity Under Utilization
Figure 3. Generic Load With Small Capacity Under Utilization

Plant utilization will be the figure of merit to measure this usage for the various types of customers. The total amount of energy needed by the customer during a year is divided by the maximum potential amount of energy produced in this generic power plant in a year, determined by the peak energy need. This produces a utilization index of electricity, which will be referred as the *"consumer load factor"*, ranging from 0% to 100%.

Table 2. Load Factor by SIC Code and Rank Ordered High to Low

SIC	Sub Category	Cap Factor	SIC	Sub Category	Cap Factor
	Office	62.27%	28	Chemicals	69.19%
	Restaurant	50.71%	36	Electronic	68.60%
	Retail	54.36%	26	Paper	66.45%
	Grocery	64.28%	37	Transportation	64.83%
	Warehouse	49.21%		Grocery	64.28%
	Education	39.29%		Hotel/Motel	62.72%
	Health	54.23%		Office	62.27%
	Hotel/Motel	62.72%	35	Industrial mach	61.48%
	Miscellaneous	36.59%	30	Rubber and Plastics	60.41%
20	Food	56.77%	33	Primary Metal	57.60%
22	Textile Mill	45.67%	20	Food	56.77%
26	Paper	66.45%	38	Instruments	54.62%
27	Printing	43.18%		Retail	54.36%
28	Chemicals	69.19%		Health	54.23%
30	Rubber and Plastics	60.41%		Restaurant	50.71%
32	Stone, clay and glass	49.95%	32	Stone, clay and glass	49.95%
33	Primary Metal	57.60%		Warehouse	49.21%
34	Fabricated Metal	37.03%	22	Textile Mill	45.67%
35	Industrial mach	61.48%	27	Printing	43.18%
36	Electronic	68.60%		Education	39.29%
37	Transportation	64.83%	34	Fabricated Metal	37.03%
38	Instruments	54.62%		Miscellaneous	36.59%
39	Misc. Manuf	34.96%	39	Misc. Manuf	34.96%

Customer load factors are calculated from the 22 customer types present in the model. The resulting load factors, shown in Table 2, indicate a wide variety of utilization between the customer with the highest load factor (Chemicals-69.19%) and the one with the lowest load factor (Misc. Manuf-34.96%). No one customer comes near a 100% load factor profile, which translates into a constant load with no capacity downtime. The nature of business and human activity reflect an uneven demand for electricity over time. Most Industrial and Commercial activity is concentrated during the day and the weekday. Less electricity is required during the off-peak hours and the weekend. Consumption is also driven by the seasons. This type of consumption "unevenness" leads to an inherent capacity under utilization, since the allocated capacity, based on the maximum capacity needs, will not be used at all times.

For instance, the Chemicals (High load Factor) customer has a load pattern with equal energy demands for both the summer and the winter seasons. Business activity for this customer is not affected by seasonal change. In addition, peak day loads differ very little from those loads in a typical weekday. With a very even and level consumption profile, capacity under utilization is minimal. The Misc. Manufacturing (Low Load Factor) customer suffers from a large amount of underutilized capacity. There is a wide mismatch between summer and winter loads. Peak day requirements are significantly higher than typical weekday needs. Since peak days seldom occur in the course of the year, much of the time, capacity allocated for peak day consumption is not being utilized. In addition, Misc. Manufacturing has a very large difference between minimum baseload requirements and maximum capacity requirements, leading to a large portion of underutilized capacity.

General Analysis of Load Patterns

The analysis from the load patterns points out that customer electricity consumption differs greatly. However, this figure of merit does not explain how particular load shape attributes influence the utilization factor. It is important to arrive at general conditions of how specific consumption features determine high and low load factors. Good attributes of consumption are identified in a qualitative manner. In Appendix B, these attributes are cross referenced to each particular customer and the calculated load factor.

Good Consumption Qualities

- Peak Day loads are similar to average weekday loads. Very little capacity is allocated that will be used for only a small amount of time.

- Seasonal energy requirements are similar. Level usage in each season permits capacity utilization increases.

- Weekend loads follow weekday energies closely. Usage in the weekend permits capacity allocated in the weekday to be utilized more effectively.

- Even/Constant usage. A load with small peaks will have little capacity under utilization.

- Broad, long duration peaks. A broad shouldered pattern better utilizes capacity for greater amounts of time as compared to a steeply increasing, short duration peaks.

Chapter 3: Long Run Costs of Electricity

Having defined the electricity customer and its consumption traits, it is possible to link supply and demand to arrive at the stand alone cost of service for specific customers in our New England market model. The consumer load factors are reflected in a generic power plant financial model, which in turn generates price streams for servicing particular customers. These price streams establish the optimal long run electricity costs that enable a power plant project to earn a fair return on investment.

Financial Analysis

A financial model is developed to evaluate the financial implications of constructing a power plant that will sell and deliver electricity to customers.[11] It is assumed that the base year of construction is 1995. This model calculates the return on equity of a power plant, given electricity prices and the utilization on the plant. Conversely, the model can calculate price streams that are needed to be charged, given a plant utilization factor and the desired rate of return. The financial model takes into account fixed and variable fuel costs, fixed and variable operation and maintenance costs, overhead, loan payback commitments, taxes and depreciation shields. Detailed assumptions are in Appendix C and D. These costs are subtracted from yearly electricity revenues to come up with a yearly cash flow contribution to the value of the project (Table 3).

Table 3. Cash Flow Computation

	Electric Sales Revenue
-	Variable Cost of Goods: O&M, Fuel
-	Overhead
-	Fixed Cost of Goods: O&M, Fuel
-	Loan Servicing
-	Taxes
	--
	Cash Flow Income (t)

[11]See Appendix F for a sample spread sheet setup

The project evaluation is calculated in a cash flow basis. Yearly cash flow totals for the project are Net Present Valued back to the base year 1995. It is assumed that the value that equity holders gain is the cash flow income that is received into the project. Return on equity is calculated based on the amount of equity invested for the project to pay for the capital costs of the plant.

The model calculates a stream of electricity prices that are constant with an allowance for the rate of inflation (Figure 5 & 6). It is assumed that inflation is 3% per year. For comparison purposes, prices quoted in this thesis will refer to the base year 1995 prices. This price path is based on the revenue requirement set by equity investors in the project. As a base case, these generic plant projects have a 20% equity/80% debt mix that demands a 20% return on equity. An electricity price path is calculated so that the equity portion of the project earns a yearly 20% rate of return. It is also assumed that by the 25th year the plant will be fully depreciated in a tax and physical plant sense.

The Basecase: Combined Cycle Servicing

The most comprehensive service that can be offered to any consumer provides for all electricity needs at all times, *the full service*. To examine how long run costs behave, as a starting point of discussion, it is assumed that the supplier has at its disposal a baseload type technology to serve the needs of its consumers. This basecase provides a point of comparison to other options that are examined later on. It is assumed that the market will completely disaggregate with a one to one matching between a single supplier and a single consumer. One supplier will provide for the needs of one customer; the utilization factor that a particular customer exhibits will match the load factor of the supplier's generic generation technology. For example, a chemical group customer that has a 68.6% utilization factor will make the plant supplying its electricity needs to be used at a 68.6% rate. This assumption provides the necessary link to estimate plant cost of service from customer load shapes.

The customer load factor figure reflects the utilization level of a plant in service to supply the load. This utilization number plays a key factor in the cost of service calculations. In estimating the cost of service for a range of utilization factors, a clear upward trend in electricity costs is seen as utilization factors decrease (Figure 4). The price of electricity becomes non linear at very low load factor percentages because heat rates at low usage levels begin to deteriorate badly.

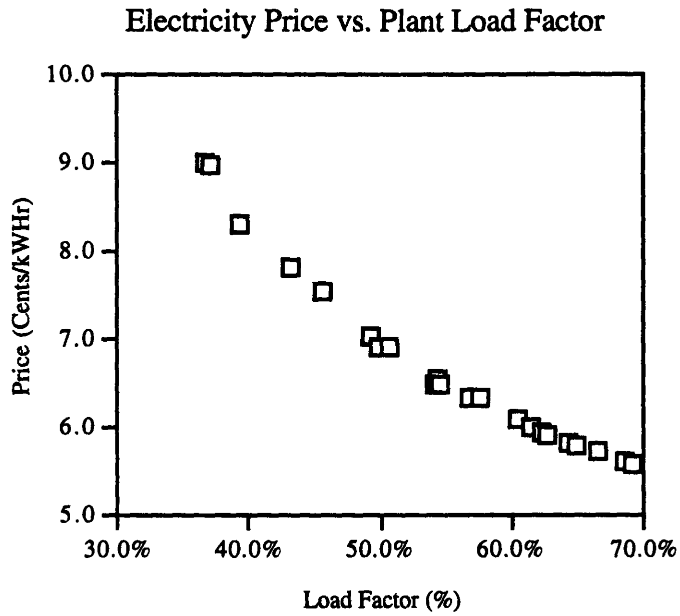


Figure 4. Electricity Price versus Load Factor

The generic plant financial model can explain the relationship between utilization factor and price. Because the model relates variable and fixed cost components to the pricing of electricity, it is possible to observe the relationship between fixed/variable costs and plant utilization. For example, a generic Combined Cycle plant that has a 70% utilization factor will be able to provide consumers 5.5¢/kWhr electricity the first year in service. Breaking this price figure into its individual components as reflected in Figure 6, the fixed component of this amount adds up to close to 3¢/kWhr . In contrast, a 35% utilization plant provides electricity that is close to 9¢/kWhr (Figure 5). The fixed O&M, loan servicing and gas pipeline cost components of the price of electricity amount to close to 6¢/kWhr. With a lower utilization factor, fixed costs have to be spread around to fewer energy units. In addition, the supplier needs to charge more per unit of electricity in order to earn enough income to satisfy equity investors. The price for electricity from a 70% utilization plant reflects a 1¢/kWhr profit allowance for equity holders. The price for electricity from a 35% utilization plant reflects a 2¢/kWhr profit allowance.

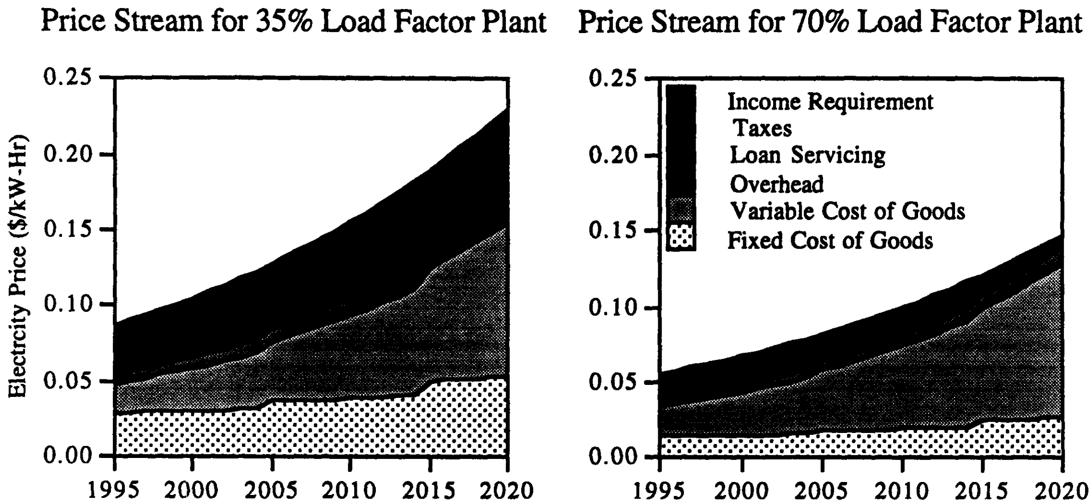


Figure 5. Components of Electricity Price for a 70% Load Factor CC Unit
Figure 6. Components of Electricity Price for a 30% Load Factor CC Unit

Evaluating the 23 customers in the New England Model, large price differentials can be seen (Figure 7). A supplier can offer Chemical groups full service electricity close to 5.5¢/kWhr. Other customers that are relatively cheap to serve are Groceries and Electronic Equipment. In the other end of the spectrum, there are various customers that are expensive to serve. New suppliers will be able to offer Misc. Manufacturing 9.5¢/kWhr electricity; Fabricated Metal will be offered 9.2¢/kWhr and Misc. Commercial will get 9¢/kWhr. All other consumers will be able to obtain electricity somewhere in between these two extremes. Variations between consumption groups have a significant impact on the price of electricity. With such a wide range of consumption patterns, a single price for electricity will not approximate the true cost of electricity. Because over and underpricing are not tenable pricing positions in a competitive market, the electricity market will have to reflect different prices for all the various consumers to link consumption with price.

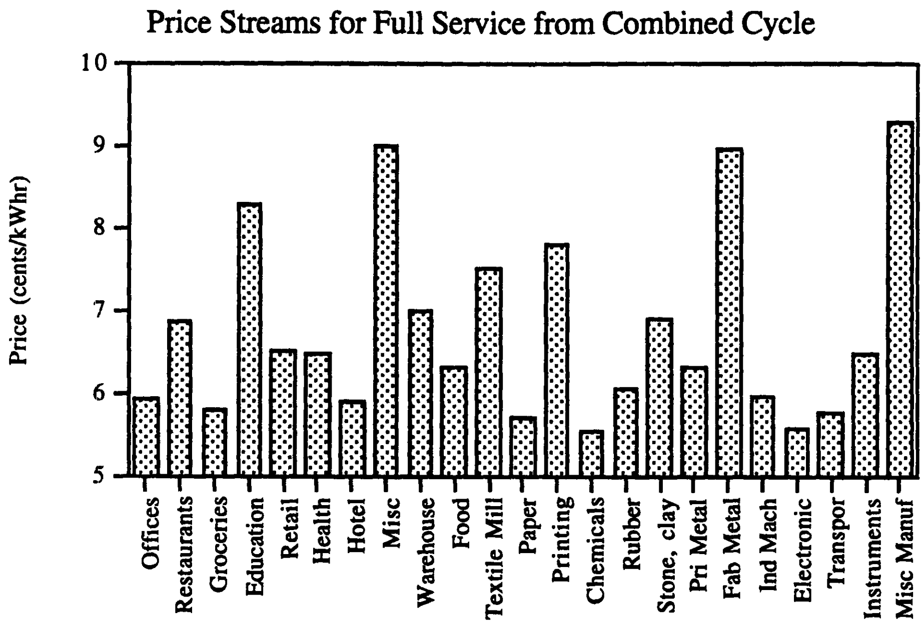


Figure 7. Full Service 1995 Nominal Price Streams

Analysis of Electricity Price Trends: Cross-Subsidization Gains

Three clear points can be taken from the examination of electricity costs in a competitive market. Price will reflect usage, cross-subsidization of services will be minimized, and there will be clear winners and losers. In a utility setting, customers are subject to prices based on system considerations rather than actual individual consumption levels. There is a great potential for cross-subsidization; utilities have problems trying to relate individual customer usage with cost of service. Much controversy exists regarding how tariffs are set to generate revenue from the various consumer classes in a utility system. In the present regulated environment, consumer groups think that they are cross-subsidizing industrial customers, and industrials think that they are helping pay for residential service.

These calculations of the electricity market price by customer type are important to determine because they define the highest cost of service that any electricity supplier can charge without exposing itself to being under cut. By calculating the price of service that a new entrant will offer to a particular customer, suppliers can assess whether the market prices are above or below their own cost of service. Because of their beneficial consumption patterns, customers with high utilization rates will be able to bargain for cheaper electricity rates from either the established utility or a new supplier. Other users with less beneficial loads will be charged an increased price for the use of electricity.

Customer gains will also be a function of how consumers have been treated by the current setup of class tariffs. Customers that have been cross-subsidized in a regulatory regime will stand to lose out as regulatory cross-subsidization vanishes; they will face the full cost of service that their load requires. It is beyond the scope of this research to point out customer groups that have been cross-subsidized in the present regulatory compact.

However, the various individual market prices and utilization factors calculated from the model give an general indication for potential suspects. Aggregated together, all 23 customer types in the New England market have a load factor of around 59.4%. If all of these customers are charged the same price based on the system load average, any customer that has an individual load factor greater than the system load factor is potentially one that has been cross subsidizing other users. Any customer that has an individual load factor that is lower than the system factor has been benefiting from implicit cross-subsidization. It is assumed that a customer with a low load factor lowers system utilization; it is also assumed that a customer with a high load factor increases system load utilization. The quantification of load factors of the various customer groups, makes it is possible to determine what customer are above and below the system load average (Table 2).

It is awkward to use this analytical method to analyze the cross-subsidization of an entire utility system since a system encompasses many customer classes and a variety of tariff settings. However, this analysis can be used to characterize cross-subsidization within a consumer class. Looking at Table 2 and Figure 7, a Commercial Education customer (low utilization-39.29%) is likely being subsidized by a Hotel customer (high utilization-62.72%). An Industrial Chemicals consumer(high utilization 69.19%) is paying the electricity for a primary metal customer (low utilization 37.03%).

Despite the model's limitations, it is still possible to examine pricing relationships between customer classes. Customers of electricity service are typically divided into three classifications: Residential, Commercial, and Industrial. In general, industrials have lower prices than commercials, and commercials have lower prices than residentials. Northeast Utilities in 1993 on the average priced Residentials at 11.56¢/kWhr, Commercials at 10.12¢/kWhr and Industrials at 8.58¢/kWhr.[12] It has been the conventional wisdom that this difference is mainly due to the more beneficial load usage that industrials impose upon the system. Commercials and residential customers are charged more because these classes

[12]Northeast Utilities. 1993 Annual Report: The Power of Change.

are more costly to serve. Based on the load factor data calculated from the model shown in Figure 7 and Table 2, this conventional wisdom is hard to reconcile.

There are several commercial groups that have higher load factors than most industrials customers. Some industrial groups that have lower load factors than most commercials. Pricing based on individual load consumption reveals a diverse range for commercial and industrial customers that does not translate into two clear cut customer classes. The lowest load factor consumers are not paying the highest electricity prices; the highest load factor consumers are not paying the lowest electricity prices. High load factor commercial groups like Groceries, Hotels and Offices are cross-subsidizing the high cost of service of high cost industrial groups like Misc. Manufactures, Fab Metals and Printing. There is a definite incongruity between pricing and utilization for industrial and commercial customers.

Some of these differences can be attributed to scale effects; industrials purchase electricity in bulk and at higher transformer voltage level than commercials. These price differences can also be explained away by the relative smaller amount of industrial customers as compared to commercial customers that utilities have to serve. However, the present literature suggests that class tariffs are heavily influenced by class price elasticities. The highest price elasticity class commands the lowest electricity prices (Industrials) and the lowest price elasticity class commands the highest electricity prices (Residentials).[13] Utilities use these elasticities to come up with electricity prices that will bring enough revenue to cover their costs of generating electricity.

This kind of incongruity between class usage and pricing can lead to a customer with a bad load factor and high elasticity(industrial) paying less than a customer that has a good load factor but a low elasticity(commercial). These transactions can be thought as a cross-subsidy. As deregulation destroys the idea of customer classes, and everybody gains the ability to shop around for low cost electricity, utilities will not be able to price discriminate; the cost shifting will end. The model presented above points to the customers groups engaged in such cross-subsidization. Low Cost Commercials will jump ship to New Suppliers. Established utilities will not be able to shift costs and will be forced to price service to consumers at their real cost of service. It is interesting to see industrials as the standard bearers of competitive electricity markets. According to the results of this

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[13]Howe, Keith and Rasmussen, Eugene.Public Utility Economics and Finance. (Englewood Cliffs:Prentice Hall, 1982) 219.

model, some of these industrials have been benefiting quite nicely from generalized price elasticity based cross subsidization due to regulation.

The pricing mechanisms for electricity are rather simple when it comes to analyzing one supplier servicing load to one customer. Established utilities will have a harder time trying to establish cost responsibilities for a system that has a variety of customers adding to the system load. It has been show in a cursory manner that current utility pricing does not reflect individual consumption load profiles. In a deregulated environment, utilities will have to change their tariffs to reflect these consumption levels and come up with more equitable cost sharing methods. Otherwise, many customer groups, some identified in this thesis, will seek lower priced electricity elsewhere.

Chapter 4: Optimizing Use of Base Load Capacity

The numbers calculated in Chapter Three establish a base level for the long run price of electricity. However, these numbers assume that suppliers have only a simple supply strategy of Combined Cycle service. In a real market, electricity suppliers will compete with each other trying to develop competitive advantages that will enable the lowering of electricity prices compared to other rivals. The extent that competitive advantages are developed will influence how much prices can drop. These advantages are usually thought as lower cost resources, capital, and labor. Ideally, in the long run, all firms will have access to the same types of inputs. Manners to differentiate between companies will turn instead to the optimal allocation of these inputs and to the optimal usage of these inputs. This chapter evaluates the extent of derived benefit that can occur by optimizing the baseload and peaking allocation technology mix. With these results, generalizations can be made on the extent that price based competition can lower prices of electricity.

Optimization Methodology

Although a Combined Cycle based strategy provides a reasonable proxy for market prices based on customer load profiles, there are more economical methods to supply these customers with electricity. Because of their high cost of installed capacity, combined cycle units are usually built to serve baseload or medium-intermediate operations.[14] There are other technologies such as the gas combustion turbine that are better suited for peaking instances and can provide cheaper electricity because of their low capacity costs.

A supplier will be confronted with the problem of how much baseload capacity to economically allocate given the requirements of a customer. Figure 8 denotes various levels of service that a supplier might offer to a generic customer . At line A, the plant runs flat out, 100% of the time, and the supplier is able to extend to the customer the

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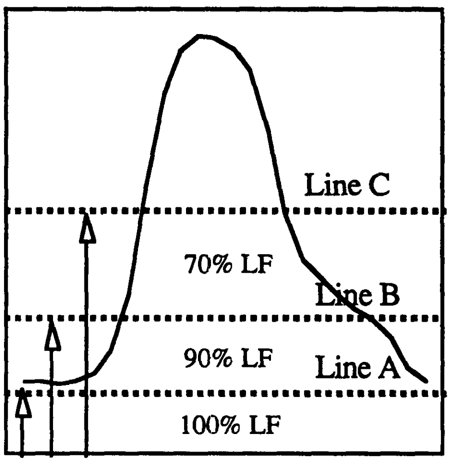
[14]Electric Power Research Institute. Natural Gas for Electricity Generation: The Challenge of Gas and Electricity Industry Coordination. Technical Report TR-101239 (Palo Alto:Electric Power Research Institute, 1992) 1-6.

cheapest available service. If the supplier tries to serve a greater increment of the customer capacity requirements, it will face a declining load factor. At the capacity level of line B, energy is needed at only certain times of the day, leaving some capacity unused at other times of the day. For most loads, this under utilization increases as less and less energy is used for each additional increment of capacity addition. At line C, total load factor service decreases further. By expanding the service contract to incorporate a greater amount of capacity, the supplier faces a declining load factor and an increased cost of service.

Plotting load factor versus percent capacity served for various customers from the model, this decreasing load factor relationship can be seen (Figure 9). While servicing a Chemical customer, a supplier will be able to utilize 100% of its plant if it serves up to 55% of capacity needs. This is due to the large amount of baseload usage that this group consumes. The total load factor then declines as the increased capacity does not get fully utilized. An education customer has a smaller amount of baseload and a larger peak. A supplier will only be able to supply 25% of education capacity with a 100% load factor. Because of the rather peaked nature of its consumption, the Education's load factor decreases severely as a greater capacity percentage is served. Each of the 22 consumer groups has a unique load pattern than defines how load factor decreases with increased capacity factor allocation. Most consumers will fall somewhere between Education and Chemicals, two customers classes with extreme opposite consumption patterns. For example, Stone, Glass and Clay has a similar baseload component as the education consumer, but its more broad shouldered variable consumption provides for greater load factors with increased capacity allocation.



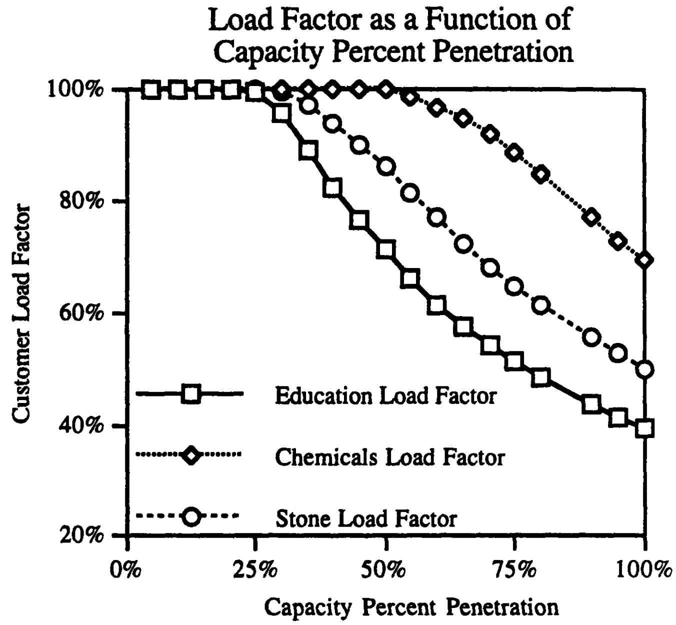


Figure 8. Schematic of Load Factor Based on Load Shape
Figure 9. Load Factor as a Function of Capacity Percent Penetration

The addition of combined cycle increments (Line A to Line B, Line B to Line C) to baseload capacity becomes increasingly more expensive as the overall load factor decreases. There will be point in the curve when the large capacity costs from a CC will make it uneconomic to serve decreasing amount of energies. The question then becomes, where is that point, and how do you calculate it? The point at which load should be provided by a peaking unit can be arrived at by examining the separate cost of service for base and peaking technologies for a range of load factors. This comparison is done in Figure 10. Using the financial model, pricing based on load factor is accomplished given a baseload combined cycle technology (CC) or a gas combustion turbine technology(GT). The CC was assumed to be running at an average efficiency of 8250 MMBTU/kW-Hr. The GT plant was assumed to be running at an average efficiency of between 17,000-21,000 MMBTU/kW-Hr.[15] For high load factors, a baseload CC is much cheaper to run given its efficient conversion of heat into electricity. Although a GT has lower capacity costs, its inefficient electricity conversion makes it a relatively expensive option. However, as the capacity load factor decreases, there is a point LF*, where both cost curves intersect and then cross. At very low load factors, it is more economical to serve electricity with a GT due to its lower installed capacity costs.

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[15]Average heat rates do not assume full ramp up rates. It is assumed that a GT follows the load exactly, hence the higher heat rates at low capacity utilization.

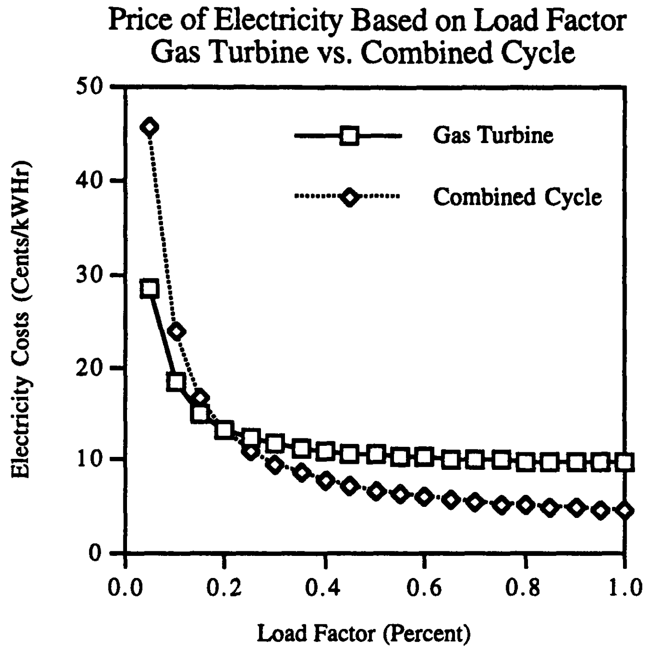

Figure 10. 1995 Electricity Price for Various Technologies by Load Factor

The crossover point in Figure 10 is the place along the capacity range where there should be a switch to Gas Turbine peaking technologies. Gas turbine capacity should be selected when the incremental load factor ΔLF_i for the next slice of capacity service ΔC_i is below that of LF^*. In this particular case, LF^*=20%. Figure 11 provides an example. At point 1, a supplier has the option to incrementally add a slice of capacity ΔC_1 that has an incremental load factor of 1.0. At this point, the technology of choice is Combined Cycle. Continuing to aggregate slices of incremental load, the supplier at capacity increment ΔC_2 will see ΔLF_2 of 50%. The supplier continues to add combined cycle plant. At capacity increment ΔC_3, very little energy is captured in the incremental capacity delta, resulting in ΔLF_3=10%. At this point, a supplier would already have switched technologies and be serving load with the alternative peaking technology.

Technology Selection Criterion

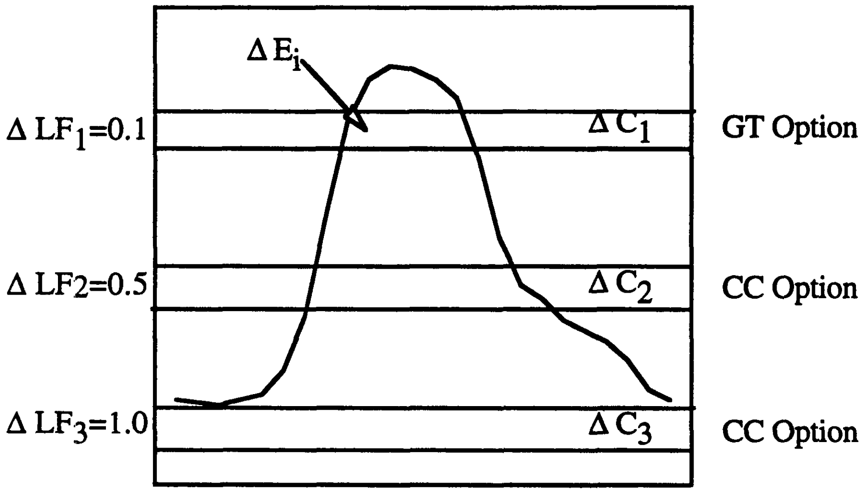

Figure 11. Technology Selection Criteria

It has been shown that methods can be developed to give the supplier the ability to customize plant allocation to supply electricity at the lowest price possible. Competitive supply planning has to take into account the detailed dynamic nature of load patterns to arrive at optimal capacity allocation solutions. The current methodology assumes a simple recurring load pattern, but in reality, suppliers and customers will have to contend with changing load patterns. More complicated and extensive methodologies will be needed to make sure load is met efficiently with minimal shortages and capacity under utilization. These types of potential optimization methodologies show clearly that the customer and supplier will become very aware of how electricity costs are affected by load pattern consumption.

Optimizing the Capacity Allocation between Combined Cycle and Gas Turbine Technology

Having arrived a methodology that optimizes capacity allocation, it can be applied to the loads of various customer groups. With these techniques, new suppliers can be assured that no other competitors can design a better service package that underbids their own package. This methodology can be used to incorporate various technologies into the allocation mix, but for simplification purposes, Combined Cycle and Gas Combustion Turbine technologies will be the only two to be considered.

To this point, price streams have been calculated for the 23 model customers as if a combined cycle supplied all load needs. It is now possible to come up with price streams that reflect the optimized combined cycle/gas turbine capacity allocation ratios. These ratios will differ for various customers, depending on the shape of the load patterns. A demand that has a lot of baseload need will reflect a large CC allocation mix. Demand that is rather peaked will tend to have a smaller CC allocation mix. To arrive at the optimal CC allocation mix, a range of Combined Cycle and Gas Turbine Capacity allocations are examined for a given customer. The load pattern is divided into a bottom segment that is served by combined cycle capacity, and a top segment that is served by gas turbine technology.

Utilization load factors are calculated separately for the two capacity segments. These utilization factors are placed in the generic CC and GT financial model to calculate separate expenditures for the two segments. These two cost streams are combined to a single electricity number; the optimal point occurs where total electricity expenditures are at a minimum. By assigning gas turbine technology to the capacity mixture, there is a range where less expensive GT capacity replaces CC expensive capacity. In this example, shown in Figure 12, the low expenditure point occurs at 65%/35% GT/CC ratio.

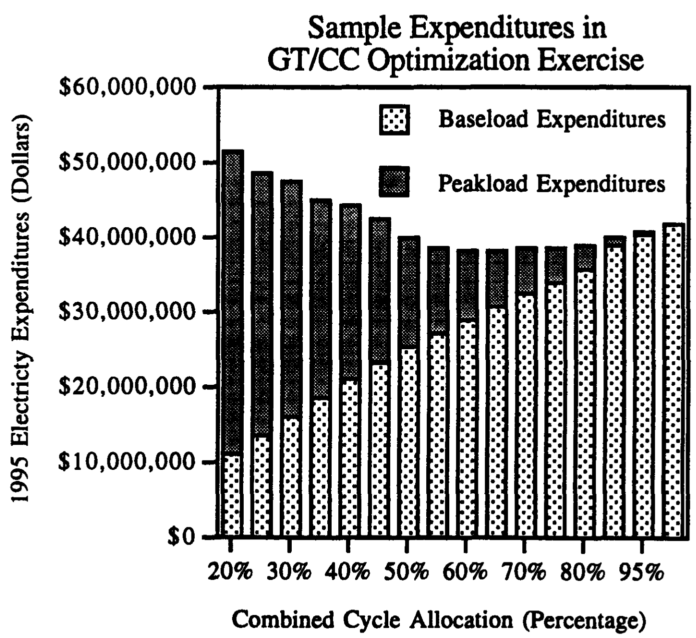

Figure 12. Total 1995 Year Expenditure with CC/GT Optimization

Results of the GT/CC Optimization

The optimal allocation of Combined Cycle and Gas Turbine technologies vary tremendously for the range of customer patterns quantified in the study. Combined cycle allocations as a percentage of the total capacity needed are presented in Table 4 and 5. Some customer groups have 80% of capacity allocated as Combined Cycle. These groups represent loads that are fairly level and compact. Others groups had combined cycle capacity allocations as low as 45%-55%. These groups exhibited load patterns that could not be served economically with large amounts of combined cycle. This scatter of optimal CC/GT ratios emphasizes what has been pointed out before; customers exhibit unique consumption patterns that have to be addressed individually.

Table 4. Price Breakdown Optimized CC/GT Data-Commercial Customers

Sub Group	Price-Full	Price-Base	Price-Peak	CC Factor
	¢/kWhr	¢/kWhr	¢/kWhr	%
Office	5.61	5.13	20.70	75
Restaurant	6.33	5.47	17.03	65
Groceries	5.52	4.92	16.31	70
Education	6.98	5.49	21.05	50
Retail	6.13	5.74	21.63	80
Health	5.98	5.32	25.51	70
Hotel	5.52	5.04	53.01	75
Misc.	7.45	5.74	15.11	45
Warehouse	6.43	5.11	12.52	50

Table 5. Price Breakdown Optimized CC/GT Data-Industrial Customers

	Price-Full	Price-Base	Price-Peak	CC Factor
	¢/kWhr	¢/kWhr	¢/kWhr	%
Food	5.91	5.40	22.36	75
Text Mill	6.79	5.51	14.97	55
Paper	5.53	5.14	16.26	80
Printing	6.86	5.53	19.84	55
Chemicals	5.37	4.98	23.32	80
Rubber	5.79	5.41	18.69	80
Stone	6.24	5.45	18.65	65
Pri Metal	5.98	5.42	20.23	75
Fab Metal	7.60	5.72	16.19	45
Ind Mach	5.70	5.05	15.49	70
Electronic	5.41	5.02	19.11	80
Transp	5.51	5.14	25.50	80
Instrum	6.00	5.19	17.41	65
Misc.	7.68	5.51	17.30	40

This capacity optimization methodology brings about cost of service savings for all customers groups. Figure 13 compares the cost of service for a range of load factors serviced by the basic All CC-Option and by the optimized CC/GT allocation scheme. Low load factor consumers typically represent usage patterns that are uneven and peaked. This type of consumption is better suited to be supplied by some amount of GT technology. Figure 14 reveals that, for the most part, the lowest load factors require the greatest percent allocation of GT capacity. Low load factor customers have very sensitive requirements when it comes to determining optimal CC/GT ratios. High load factor customers gain very little in absolute cost from this optimization as seen in Figure 13.

Capacity allocation optimization for high load factor (70%) customers is small. There is a savings of 0.2 ¢/kW-Hr on 5¢/kW-Hr electricity . This amounts to a 4% decrease. As load factor decreases and optimization can lead to better capacity allocation efficiencies, absolute and percentage savings increase. With the optimization, the lowest load factor (35%) consumers save close to 1.5¢/kW-Hr on 9¢/kW-Hr electricity. This amounts to a 17% decrease in electricity price. These calculations reveal that capacity allocation optimization does influence the pricing in a deregulated competitive market. These kind of methodologies can be used by suppliers to gain competitive pricing advantages, undercutting rivals and at the same time, driving the price of electricity downwards. The market becomes more efficient as a result of the application of this methodology, increasing competition, which in turn, benefits the ultimate consumer.

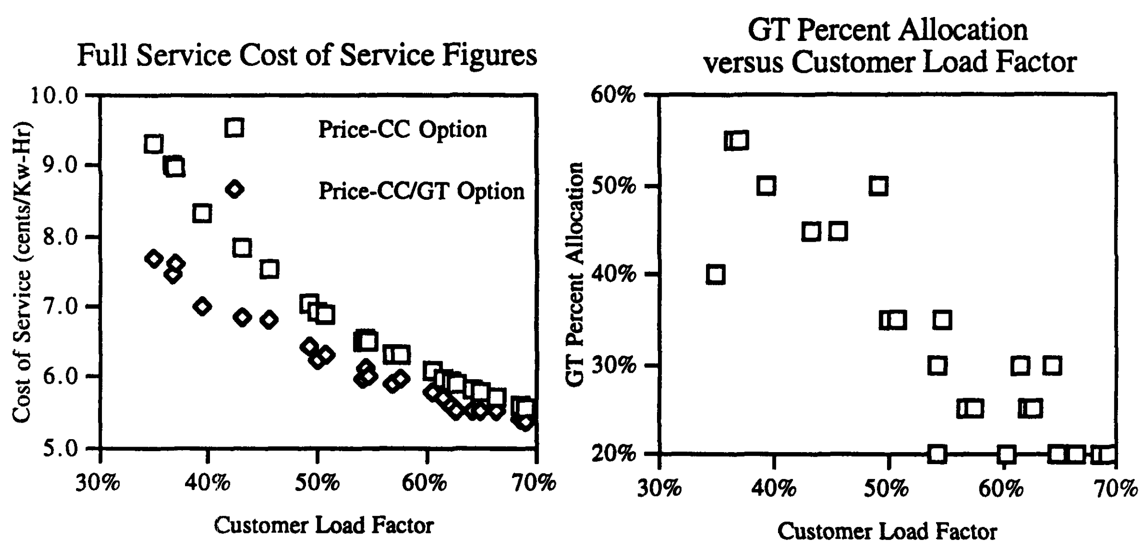

Figure 13. Pricing for Optimal CC/GT Combination
Figure 14. GT Percent Allocation versus Customer Load Factor

Optimization Implications for Consumers and Suppliers

If a supplier decides to enter the market by providing low cost service based on capacity optimization, it faces a variety of uncertainties. Not only have suppliers to contend with the operational needs of various types of generating units but also have to come up with the precise mix of CC and GT capacity to construct and allocate. Incorrect capacity calculations will cause the customer to refuse the service or leave the supplier for other alternatives that have better optimized mixes. Having optimized its capacity allocation for a particular customer group, a GT/CC supplier can ill afford to have its customers leave. The supplier would be forced to find another customer that matched the load profile of the departed customer. Otherwise, this supplier has to compete for other customers with an unoptimized capacity package.

For example, Supplier A allocates a 40%/60% CC/GT capacity mix to serve a Misc. Manufacturing customer (Figure 15). This ratio minimizes the cost of service for this particular consumer at 7.68¢/kW-Hr (Point 1). The Misc. Manufacturing customer decides to leave the contract. To efficiently produce electricity, supplier A has to find another customer that has a load optimized for a 40%/60% CC/GT mix. If it can not find such a customer, Supplier A has to compete for customers that are best served with other capacity allocation ratios. Suppose Supplier A competes for a Chemical customer that is best supplied with a 80%/20% CC/GT ratio. Supplier A can bid 6.60¢/kW-Hr for the electricity based on its capacity allocation ratio (Point 2). Supplier B, with an optimized capacity ratio of 80%/20% CC/GT, can bid all the way down to 5.38¢/kW-Hr (Point 3). Supplier A will invariably lose unless he can come up with non-cost advantages. Risk minimization measures such as long term contracts and long lead time departure notices will have to be instituted in the market segment to ensure that these suppliers don't get in trouble in the long run. Although CC/GT capacity optimization has a great potential to lower costs, it also creates supply uncertainty and risks. These risks invariably will be added to the cost of electricity as a price premium.

If exact load usage information is scarce or unavailable, suppliers will have less than perfect information to calculate optimal capacity ratios. If suppliers generally know that a customer has a high load factor, Figures 13 and 15 show that these suppliers can minimize risk by to allocating close to 100% of baseload capacity. The cost differential between an all baseload allocation and the optimal capacity allocation is small for high load factor customers. This kind of strategy will not place the supplier at a large competitive disadvantage since costs will not be very far off from the optimal low cost. Suppliers with this strategy keep the flexibility to sell their baseload plant to other customers without the worry of maximizing GT capacity. Suppliers that want to supply low load factor customers assume greater uncertainty since there is greater room for error. They can not hope to play a conservative capacity allocation. Faced with uncertain information, these suppliers might want to have a 50%/50% general rule of thumb. A 100% CC or a 100% GT allocation lead to highly unoptimal costs. Based on the model results, it is more risky to serve low load factor customers than high load factor customers This riskiness might be translated into increased prices for the low load customers to compensate for the potential instability of consumer demand. The low load factor customer that already has high costs will have to pay even more because of the untenable position that they place suppliers.

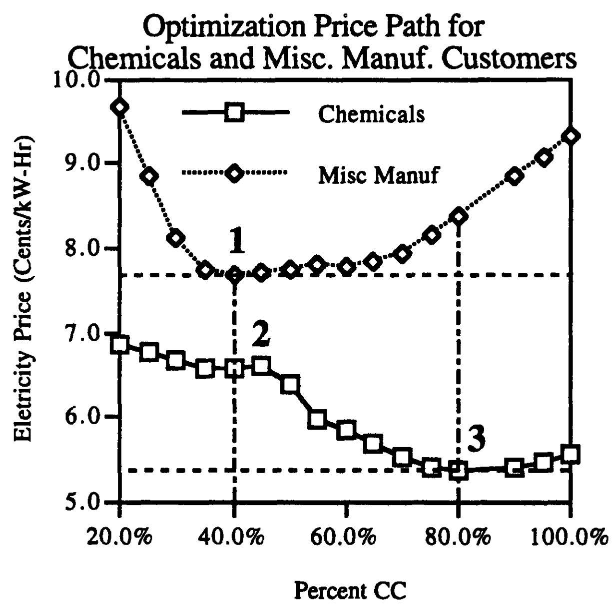

Figure 15. Risk Potential for Customer Switching

Pricing Breakdown: Pricing Baseload and Peak load Service

Optimal service involves the use of both baseload and peaking technologies that are combined to form a full service package. The full service price can also be thought as the combination of the individual costs of baseload service and of the peaking service. These prices provide an upper baseline for the pricing of niche service options. The full rundown for these price breakdowns are included in Table 4 and 5. For example, the optimized capacity allocation procedure for an Office customer requires 75%/25% Baseload/Peak service. The full service price is 5.61 ¢/kW-Hr(P_{fs}). The baseload segment is priced at 5.13¢/kW-Hr (P_b) and the peaking segment is priced at 20.70¢/kW-Hr.(P_p) An office customer will never contract for baseload service for more than 5.13¢/kW-Hr since the customer can get that implicit price in a full service agreement. Niche suppliers of electricity have to price below these baselines (P_b, P_p) to have customers switch to their service. Companies specializing in niche service will have to seek out competitive advantages in order to come up with pricing options that will undercut the optimized full service levels. The next chapter will bring forth ideas and methodologies that might enable niche players to undercut these optimal segment prices(P_b, P_p, P_{fs}).

Having a methodology that calculates segmented service options will enable established utilities to determine how to price for customers that want to partially leave the system. For example, assume that a commercial Groceries customer pays the established utility 10¢/kW-Hr. If it decides to fully switch to a new supplier, the Grocery customer will expect to pay 5.52¢/kW-Hr (Table 4). If it contracts for baseload service to the new supplier, it can expect to pay 4.92¢/kW-Hr. The Grocery customer will then argue with the utility to provide the remaining leftover peak demand for 10¢/kW-Hr. However, the established utility will not provide the remaining peak needs of the Grocery with this average tariff. It knows, or at least should know, that peaking service can not be supplied by new suppliers for less than 16.31¢/kW-Hr.

Not knowing how to price these different levels of service in a competitive environment will make established utilities end up in a more precarious competitive position than they already are. If utilities price much below the level new suppliers can enter at, they will keep the customer but will lose revenue needlessly. In the Grocery customer example, if an established utility prices peak service at 13¢/kW-Hr when the competition can not provide it for less than 16.31¢/kW-Hr, established utility will needlessly give the customer 3.31¢/kW-Hr. In some situations, this undercutting of services could be construed as predatory pricing, intentional or unintentional as it might be. If utilities price above the level new suppliers can enter at, they will be severely undercut. If utilities try to recover extra revenue by pricing peaking service above 16.31¢/kW-Hr, for example, it will be very likely that they will be underbid. New suppliers will be setting the competitive market price in the long run. It will be easy for them to have a handle on profitable pricing levels. Established utilities will have a tougher time trying to establish competitive and profitable pricing levels since they will not be a factor on the actual market pricing. These types of market models can help determine cost of service for rival competition.

Allocation Dynamics

Although the optimal allocation of CC/GT can be seen as a function of load utilization, this relation does not correlate perfectly. As demonstrated earlier in the chapter, the decision to switch from combined cycle to gas turbine is based on the incremental capacity load factor, rather than the average load factor. From Figure 14, it does not seem that the average load factor figure captures all the nuances that can influence the incremental capacity factor. To get a better sense of the dynamics of where the correct GT/CC cutoff point is and what influences it, load shapes have to be analyzed.

From the heuristic derived in Figures 10 and 11, the switching point between GT and CC technologies is based on an incremental load factor derived from the economics of CC and GT technologies. When the incremental load factor for a given load shape reaches this cutoff incremental load factor (LF^*), technology switching occurs. For a group of customer load patterns, this cutoff occurs at a large percentage of the total capacity(70-80%). Examining this group of loads, it becomes apparent that they have the most balanced energy usage across seasonal and daily load pattern. A representative load patterns is shown in Figure 16. Typical consumption in weekdays for the summer and winter are evenly balanced, and the incremental load factor threshold only occurs at the top part of the curves. Small differences between typical and peak day consumption tend to minimize the deterioration of the incremental load factor. These customers tend to have a large constant baseload portion compared to its peaking portion. Energy consumption decreases will only occur at higher capacity factor percentages.

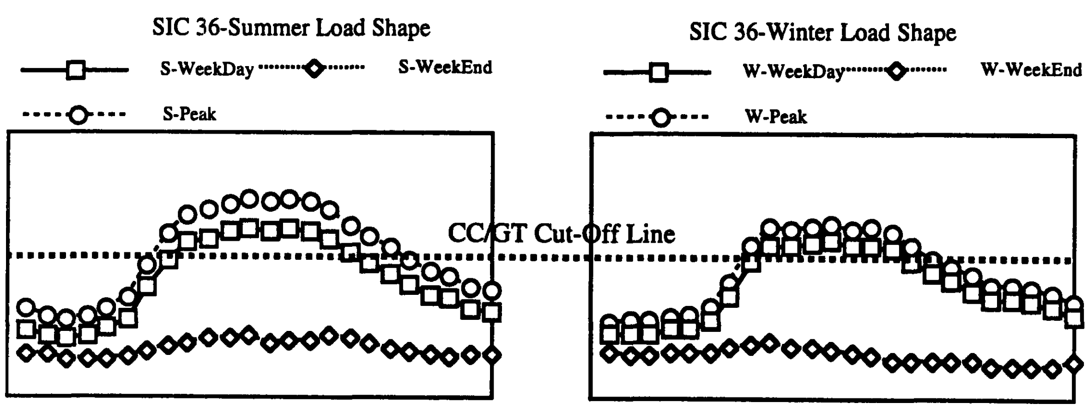

Figure 16. High Baseload Capacity Allocation

A second tier of customer load shapes has been allocated a lower percentage of baseload/combined cycle capacity (60%-70%). The cutoff incremental load factor is reached sooner because these shapes exhibit slight unevenness of energy consumption across seasons as seen in Figure 17. The 20% incremental load factor is reached when the consumption in one season tails off while the consumption in the other season still is high. Because each season is half a year, electricity consumption that is not matched properly will lead to large non utilization gaps which make the GT technology optimal more readily.

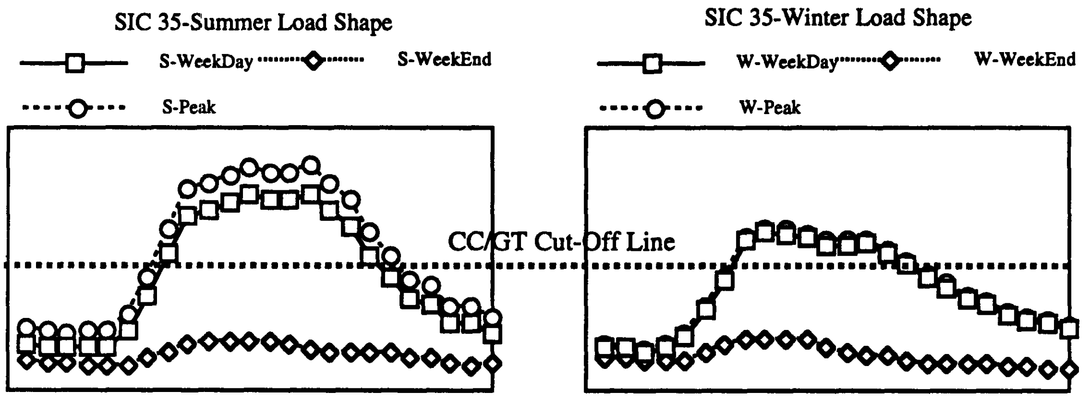

Figure 17. Medium Baseload Capacity Allocation

A third set of customer have been allocated with very low capacity percentages(45%-65%). These customer groups have the most uneven seasonal distribution as seen in Figure 18. These customers tend to have very peaked consumption profiles. The ramp up from off-peak consumption to on-peak consumption is very steep, causing the cross-over load factor to be reached at a low capacity percentage. These customer types tend to have a small baseload consumption as compared to their peak.

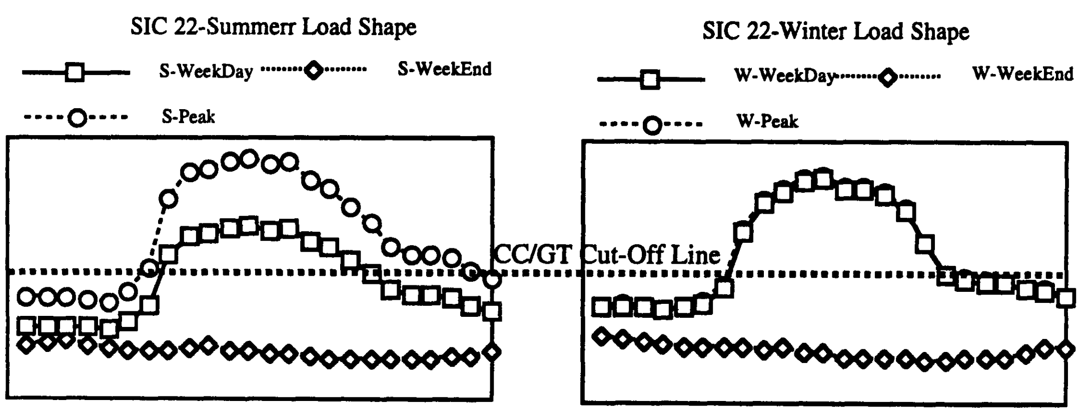

Figure 18. Low Baseload Capacity Allocation

Chapter 5: Diversity Optimization

The previous one-supplier one-customer model revealed interesting analysis regarding customer and supplier behavior in a competitive deregulated environment. However, this exclusive service transaction model between customer and supplier does not take into account the multitude of other customers in the market that a supplier can serve. The next extension to the model considers a single supplier serving more than one customer at a time. Load aggregation is defined as the addition by a supplier of two or more customer load patterns to create a third. The effects of load aggregation are quantified to examine the extent of utilization benefits in combining the load demands of various customers.

Methodology

Energy requirements differ for each customer over time. Some load profiles have large energy requirements during the summer, others during the winter. Other load profiles have high afternoon requirements; others have high evening or night hour requirements. Complementary aggregation is defined as the matching up of low and high energy time periods use of different consumers so that the resulting aggregated pattern has an overall more uniform shape and higher load factor. For example, let's take a user that has a heavy winter energy use (Figure 19). The SIC 20-Food group peaks in energy use during the winter and has an over-all utilization energy factor of 56.76%. During the summer it has a utilization factor of 48.99% and during the winter, it has a utilization factor of 64.54%. Capacity requirements and energy requirements are very uneven between the two seasons.

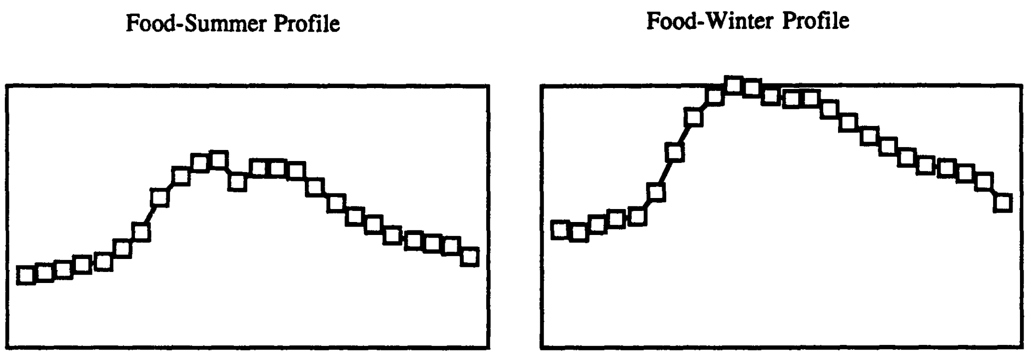

Figure 19. Winter Peaking Load (SIC 20-Food)

A second customer group that will be examined is a heavy summer energy user (Figure 20). The SIC 32-Stone, Clay and Glass (S,C&G) customer group has an overall utilization of 49.94%. Summer utilization is 59.82% and Winter utilization is 40.07%.

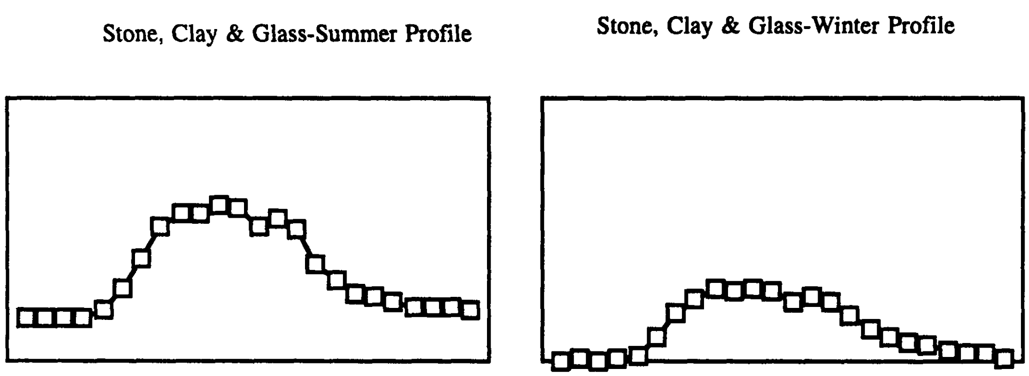

Figure 20. Summer Peaking Load (SIC 32-Stone, Clay & Glass)

With complementary aggregation, the low winter usage of S,C&G is added to the high winter usage of the Food customer. The high summer usage of S,C&G is added to the low summer usage of the Food customer. The resulting pattern is an aggregated load profile that has both high summer and winter usage which results in a more level load pattern with better utilization (Figure 21). The resulting pattern has a summer utilization of 62.93% and a winter utilization of 61.53%, resulting in an overall utilization of 62.23%. By combining these two customers together, it is noted empirically that the resulting utilization is improved.

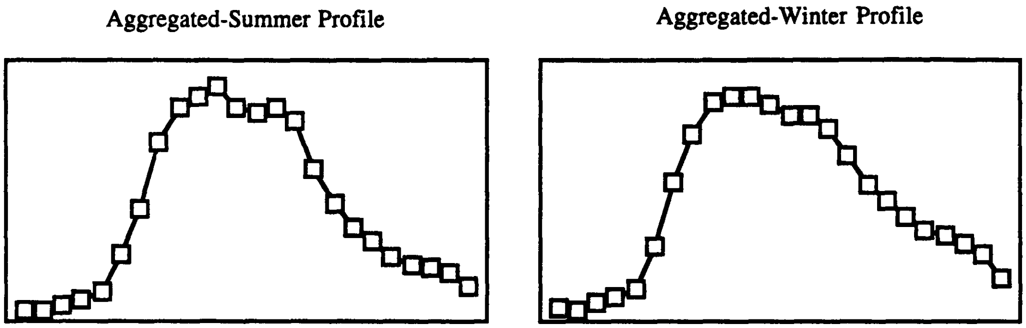

Figure 21. Aggregated Load

The effectiveness of this aggregation depends on the ability of the aggregating entity to find load patterns that exhibit complementary usage. Two groups that have heavy coincidental usage, heavy summer usage, for example, will not be able to match up low consumption periods with high consumption periods. For example, Education and Transportation have heavy winter energy usage. Aggregation will result in two high summer energy users being combined to form a high summer consumption period. Two low winter periods are added up, resulting in a low winter consumption period. Energy needs are still disproportionately biased towards the summer, leaving a large winter valley. The aggregation leaves a summer utilization of 35.62%, winter utilization of 50.76%, and an overall utilization of 43.19% (Table 6). This aggregation results in a utilization factor that does not have a beneficial utilization synergism. Unlike the last example, the aggregated consumers do not benefit from this transaction. Education increases its load factor to the detriment of Transportation; this aggregation is not Pareto optimal.

Table 6. Non Beneficial Aggregation

	Summer Utilization	Winter Utilization	OverAll Utilization
Education	31.76	46.82	39.29
Transportation	57.03	72.63	64.83
Aggregation	35.62	50.76	43.19

With such a potential advantage in aggregating customers, it follows that suppliers with aggregated customers should have the potential to offer lower prices than those suppliers that exclusively serve one customer. Not only would new suppliers be competing against established utilities, but also with other new suppliers that might have better, more sophisticated aggregating techniques.

Basic Aggregation Methods

The use of such techniques brings out the point that there will be a tremendous amount of demand for data discovery for all types of customer loads in order to analyze and piece together synergistic aggregations. Customers that stand to gain from this technique will reveal their consumption patterns gladly. Other customers that do not have such beneficial characteristics might be less inclined to reveal their consumption patterns. Suppliers will have to know the level of consumption that occurs, and metering will have to be done at a large scale and with more precision. In the early stages of the market, suppliers, new entrants in particular, will have little notion of the actual consumption profiles of these potential customers. There will a serious data void that suppliers and customers will have to deal with in order to come up realistic and optimal allocation of baseload and peak load plant capacity.

In this context, present utilities have a competitive advantage over potential new supply entrants. Presently servicing electricity customers , utilities have potential access to this type of load information as part of their metering abilities. However, it does not seem that many utilities have availed themselves of much of this information at the single consumer level at the present time. It is not an important sets of numbers for a utility that looks merely at total energy and peak capacity for pricing information. It will be a matter of time until utilities begin to discover the value of this type of capacity load vs. time information for all consumers, big and small. This type of load pattern information for specific individual customer can become the competitive advantage that established utilities so sorely need.

Given the potential benefits from aggregating complementary customer loads, a need arises to develop meaningful heuristics to create good aggregation methodologies. From the simple mathematical exercise above, successful aggregation is due to in part to matching non coincidental energy consumption. Various methodologies can be devised to come up with synergistic aggregate loads. For instance, a supplier might add together segments that have peaks occurring at different times of the day. Examining the hourly peaks for commercial customers, the hotel segment (Peaking at 19 Hrs) can be combined with the Health segment (Peaking at 11 Hrs) since peaks occur at non coincidental times. Customers that should not be aggregated together are Education/Misc. and Office/Warehouse since these segments combinations have coincident or near coincident peaks that do not permit synergistic, capacity saving aggregation.

A second way that consumer segments can be aggregated is to match customers with a large summer peaking consumption with other customers that have winter peaking consumption. From the information in Table 7, winter and summer peaking customers can be separated. A hotel customer (Winter) might be paired up with a SIC 27 Printing customer (Summer) to balance out seasonal demand. An SIC 36-Electronics (Summer) group can be matched up with a SIC 20-Food (Winter) group. Depending on the methodology used, customer aggregation can be very coarse as the methods used beforehand, or as sophisticated as linear programming and optimizing routines.

Table 7. Customer Groups Classified by Seasonal Usage

Summer Peaking	Winter Peaking	Summer and Winter
Restaurants	Office	SIC 22-Textile
Retail	Education	SIC 26-Paper
Grocery	Hotel	SIC 28-Chemicals
Health	SIC 20-Food	SIC 30-Rubber
Misc.-Com	SIC 37-Transportation	SIC 33-Primary Metal
Warehouse		
SIC 27-Printing		
SIC 32-Stone, Glass & Clay		
SIC 34-Fabricated Metal		
SIC 35-Industrial Machinery		
SIC 36-Electronic		
SIC 38-Instruments		
SIC 39-Misc. Manufac		

Numerical Aggregation Algorithm

To further examine the potential for customer aggregation in a competitive market and assess the long run electricity price shifts, a quantitative market aggregation model is constructed. The commercial and industrial loads for three New England Utilities (NEES, BECO, NU) are collected together. This collection of customers defines the market where competition is waged by suppliers in this model. The model is closed to the outside world, and all customers have to be served by either new suppliers or the established public utility system. A supplier is allowed to serve any amount of consumer load for a given segment up to the sum of the consumer load for the three utilities. A supplier is allowed to combine any number of customer groups to bundle its service package.

Because of the wide range of customer types, there is lots of flexibility in the manner a new supplier can combine these groups. A supplier might want to improve load factors for its best customers (Chemicals-4.60¢/kWhr, Hotel-4.70¢/kWhr) to protect them from other suppliers. In the other hand, a supplier might want to reach out to costly customers(Education-8.60¢/kWhr, Fab Metal-9.40¢/kWhr) and create a package that will improve their load factors. These attempts lower prices for high cost customers and enable suppliers to develop a competitive advantage over established utility service and other suppliers. Combination opportunities are many and will depend on the strategic positioning of the firm doing the aggregation. To quantify the effects of consumer aggregation upon long run marginal prices, an aggregation strategy and methodology is proposed and carried out for the proxy New England market. This methodology is by no means an optimal set of the various combinations and there is no attempt to establish or prove an optimal criteria of groupings.

Methodology of Segment Groupings

The methodology presented here maximizes the load factors of the best customers to provide minimum prices to the already least costly groups. It is as follows:

- Take 100% of the consumer type with the highest load factor and combine complementary customer types in such a way to create the highest load factor.
- Proceed to the next best customer and add from the remaining groups to provide the best improved load factor.
- Proceed again until all customers are assigned to a group.

This heuristic is accomplished by a numerical solver in an EXCEL spreadsheet that finds the optimal combination of consumer contribution ratios that will maximize a certain load factor (Appendix J). Each consumer is quantified as a mixture of the six representative load shapes derived prior in this research. Because there is one variable for each customer group, the number of variables make optimal aggregation a complex optimization problem. Using this aggregative model, it was found that the solution has a variety of local maximums that the numerical solver package sometimes converged upon rather than the optimal maximum. This phenomena became apparent as solutions to the optimizations varied with the initial variable state. To attempt to solve for an optimal solution with real dollar implications, very robust analytical tools will have to be developed to surmount these types of problems. Otherwise, suppliers might aggregate packages that are sub optimal and create opportunities for other competitors with better aggregation techniques to assemble better service packages. Again, competitive advantages can be achieved by those suppliers that have creative thinking and robust algorithms.

Results of Aggregation

By following the aggregation heuristic outlined above, the entire New England market can be aggregated. Table 8a and 8b show the results from this exercise. To increase the load factor of the best customer, SIC 28-Chemicals, 100% of the hotel group and 22.34% of the grocery groups are combined. This aggregation results in a combined segment load factor of 73.27%, increasing the utilization factors for all three customers. Examining the resulting aggregated load pattern, it is found the numeric algorithm aggregated loads to primarily balance out seasonal mismatches. It sought out combinations of customer groups that filled in the low energy valleys until the peaking load for the summer season equaled the peaking load for the winter season. The aggregation pattern for all runs had this characteristic; no optimal solution has mismatched peaks.

Table 8a. Optimized Supplier Customer Segment

Sub Group	Load Factor	% of Cap	Subgroup	Load Factor	Capacity
Chemicals	69.19	100.00	Segment 1	73.27	324.77
Groceries	64.28	22.34			
Hotels	62.72	100.00			
Electronic	68.60	100.00	Segment 2	69.51	299.61
Transport	64.83	2.14			
Offices	62.27	1.82			
Education	39.29	3.55			
Paper	66.45	100.00	Segment 3	72.43	532.86
Transport	64.83	97.86			
Groceries	64.28	58.88			
Groceries	64.28	18.79	Segment 4	67.08	996.21
Offices	62.27	38.87			
Industrial	61.48	100.00			
Food	56.77	19.04			
Offices	62.27	59.30	Segment 5	66.51	1113.38
Instruments	54.62	7.20			
Restaurant	50.71	55.04			
Rubber	60.41	100.00	Segment 6	63.42	285.05
Instruments	54.62	7.20			
Retail	54.36	3.72			
Restaurant	50.71	6.20			
Primary Metal	57.60	100.00	Segment 7	60.14	243.71
Food	56.77	2.11			
Instruments	54.62	1.54			
Retail	54.36	7.00			
Health	54.23	4.11			
Restaurants	50.71	4.31			
Stone,Clay,Gla	49.95	1.33			
Printing	43.18	1.01			

Table 8b. Optimized Supplier Customer Segments (Cont.)

Sub Group	Load Factor	% of Cap	Subgroup	Load Factor	Capacity
Food	56.77	78.84	Segment 8	65.64	138.14
Instruments	54.62	3.93			
Retail	54.36	4.51			
Restaurants	50.71	7.31			
Stone,Clay,Gla	49.95	1.01			
Instruments	54.62	85.25	Segment 9	61.82	311.14
Restaurants	50.71	27.14			
Education	39.29	21.65			
Retail	54.36	84.76	Segment 10	59.93	1063.26
Health	54.23	65.34			
Stone,Clay,Gla	49.95	18.03			
Education	39.29	44.92			
Health	54.23	30.55	Segment 11	58.38	188.31
Education	39.29	6.79			
Stone,Clay,Gla	49.95	79.63	Segment 12	56.80	216.87
Printing	43.18	98.98			
Education	39.29	13.99			
Warehouse	49.21	68.44	Segment 13	51.05	240.86
Education	39.29	3.31			
Warehouse	49.21	31.56	Segment 14	48.18	174.26
Textile Mill	45.67	88.78			
Textile Mill	45.67	11.22	Segment 15	38.43	768.87
Fabricated Met	37.03	100.00			
Misc.-Com	36.59	40.15			
Misc.-Com	36.59	59.85	Segment 16	36.58	861.84
Misc. Manuf	34.96	100.00			

The final aggregated pattern for these three customers is shown in figures 22a-22f and reveals details that need be considered while aggregating loads. To increase utilization, segments are primarily composed of summer users matched up with winter users. To compose Segment 4, heavy Summer users Groceries and Industrial Machinery are combined with heavy Winter users Offices and Food. Secondary features of aggregation establish allocations based on time of day complements. In Segment 5, Restaurant Evening consumption energy is matched up with Morning/Afternoon consumption energy. Utilization can also be improved by leveling off weekend consumption. In Segment 6, morning weekend Rubber energy consumption is leveled off by evening Restaurant and Retail weekend energy consumption.

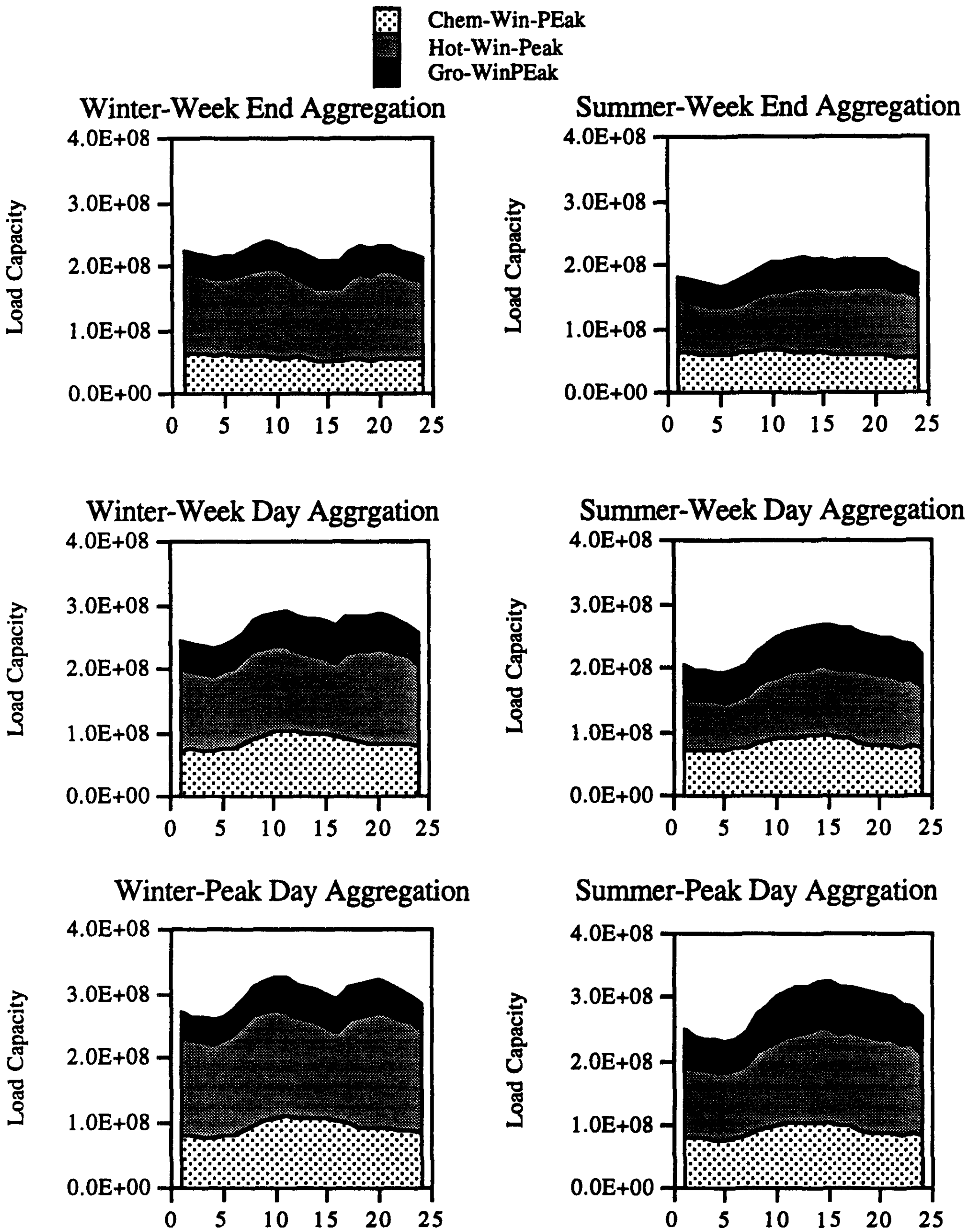

Figure22a-22f. Aggregated Loads for Chemical Segment

Examining the utility factors for the all resulting aggregated segments, all customer groups benefit from this aggregation technique. Moving from a completely disaggregated model to one that is "optimally aggregated" makes everybody better off. If done properly, this aggregating techniques can be Pareto optimal for all groups in the market. In Figure 23, a graphical representation of the effect of aggregation is presented. It shows the load factor for all kilowatt-hours present in the market. The simple strategy reflects the capacity factors for customers being served individually by suppliers. The optimized strategy represents the aggregation methodology presented previously. The wide separations of the two graphs show the load factor gains from aggregation. In addition, the established utility system load factor is overlayed in this graph to examine how these two supply strategies compare to the load factor of that a utility has with all representative customers. This graph shows clearly that many customers can obtain large cuts in electricity prices by obtaining service from new providers of electricity.

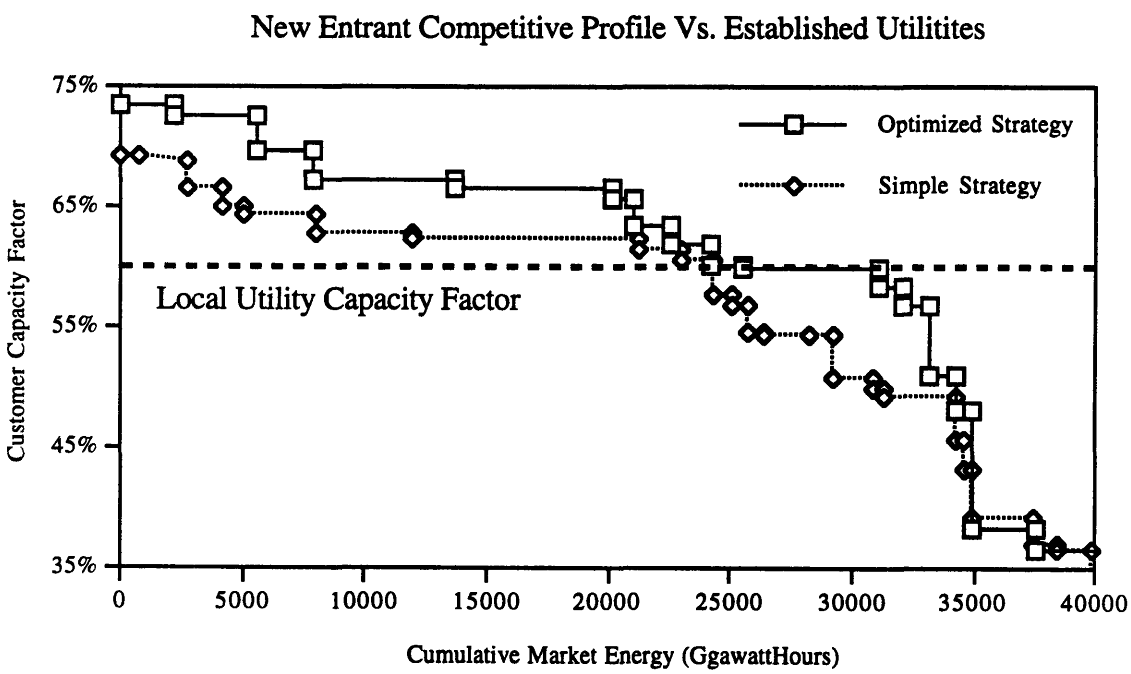

Figure 23. Effects of Aggregation Upon Competitive Market

There are some instances where optimal aggregations are being made with load patterns that exhibit poor load factors and are very expensive to serve as stand alone customers. Because some of these low factor customers have complementary load traits that can help out other customers with their aggregation, they become very valuable groups. For instance, the Education, with a 39.29% capacity factor is one of the most expensive customers to be served. Nevertheless, this customer brings some kind of benefit to the aggregation to Segment 2, to help bring the overall segment capacity factor to 69.51%. Education also helps out in other segments; Education is a heavy Winter Peaking/Energy customer. This type of customer is a perfect match for customers that are heavily Summer Peaking and Energy intense. The definition of an expensive customer to serve becomes blurred as expensive customers individually can allow for cheaper electricity in the aggregate. Food and Restaurants have some kind of complementary effects upon the load they aggregate into. Not all customers exhibit this kind of complementary effect. Other customers do not have these features and can not be aggregated into other groups effectively. Such is the case for Miscellaneous Manufacturing and Miscellaneous Commercial entities. They are the truly worse off customer entities in this competitive market.

Given these utilization synergies, the proper allocation of the aggregation savings becomes a contentious issue. This task parallels that of current utility efforts to establish cost of service allocation methodologies for various customer classes. Although every customer group contributes to these aggregation gains, the distribution of these benefits is left to the aggregator and/or the supplier rather than a centralized public utility commission. The market will determine who will eventually savor the benefits of aggregation; it is a very dynamic problem to deal with. If a member of an aggregated segment does not like the way aggregation benefits are distributed, the customer can decide to leave and look for a segment group that will provide it with a better benefit cut. Given the large amount of customer combination types, the possibilities are endless. The complementary aspects of load shapes will measure the extent of bargaining power that any given customer will have.

Question of Efficiency

In an market with completely accessible disaggregated customers, suppliers can provide service by allocating a certain amount of capacity to meet the needs of customers. If suppliers begin to aggregate these groups together, synergistic effects are seen and less capacity is needed to supply the same amount of energy. Let's look at the First Segment allocation as an example.

In the proxy New England market, Chemicals require 111.45 MW of Capacity, Groceries require 74.05 MW of Capacity and Hotels have 180.51 MW. Serviced separately, they represent 366.21 MW of capacity need. However, serviced in aggregate terms, they represent 324.77 MW of load. There is a considerable savings of capacity allocation as load is aggregated. Intuitively, this makes sense, but brings out a very interesting question. At what level of aggregation is this capacity savings maximized? Do savings continue until all load is aggregated together, or is it a function of a particular optimized series of combinations. If maximum capacity savings occur when all load is aggregated together in one group, this would imply that the optimal level of size for a firm would tend towards a single company service. Competitive markets can bring excess capacity allocation.

It is beyond the scope of this thesis to examine what the optimal capacity allocation would be, but the model setup provides data that can assess this question in a qualitative manner. The New England model has a market area that encloses customer groups for three separate utilities. Since there are 22 customer groups in each utility area, there is a potential of 66 different customer groups that can be served by individual suppliers. This scenario reflects the most disaggregated manner of customer service that can be reflected by this model. Adding up the individual peak capacity requirements for the separate 66 customers, there is a requirement for 8617 MW of capacity. In the competitive aggregation scenario, laid out in Chapter 5, suppliers maximized their service load factor by aggregating together bits and pieces of consumer load. This led to a 16 piece segmentation of the market. Adding up the individual peak capacities for this 16 segment market, there is a need for 7759 MW of capacity. By having competitors aggregate loads to maximize load factor and becoming competitive in the market place, there is a synergistic savings of 858 MW. If customer loads are aggregated to the present customer mix of the three public utilities, the peak capacity requirements for the three utilities add up to 7733 MW. If all customers are aggregated together to a single mega customer, the synergistic aggregate effects of a single peak bring the requirements down to 7725 MW.

Table 9. Capacity Requirements by Aggregation Stage

Aggregation Stage	**Capacity Requirement**
Multiple Supplier	8617 MW
Competitive Aggregation	7759 MW
Public Utility Sector	7733 MW
Mega-One Consumer	7725 MW

As the level of consumer aggregation increases, total capacity requirements decline (Table 9). The synergistic effects of capacity allocation are greatest with a complete aggregation of the market. This model simulation reveals that a competitive marketplace with multiple suppliers and multiple consumers has the potential to create a significant amount of excess capacity allocation. However, if the market exhibits any kind of competitive aggregation, this excess capacity allocation is reduced to minimal levels. There is every incentive by suppliers to aggregate loads in order to increase load factors and revenues; competition will drive suppliers to aggregate loads and minimize excess capacity allocations. From the results from this model, a competitive market would incur minimal inefficiency penalties; any assertion that competitive markets would bring about large excess over allocation of capacity does not bear forth in the constructs of this model.

Chapter 6: Summary and Policy Perspectives

Conclusions

This thesis examined the long run costs of electricity in a competitive market. It also evaluated the possibility and magnitude that competitive advantage techniques could lower the price of electricity. Various conclusions can be presented from this research.

- There is a large range of cost of service attributed to the various customers in the electricity market. However, complementary traits can enable a customer class to aggregate itself to better electricity prices.
- The CC/GT Optimal Capacity Allocation heuristic can lower the cost of providing electricity, but this technique has risks involved with it.
- Aggregation of customer loads provides for extensive opportunity to improve load utilization factors for supplier power plants. Higher plant utilization factors and minimization of capacity allocation lead to reduced electricity costs for all consumers.
- The monetary sharing benefits of aggregation will be determined by supplier and customer bargaining power rather than a centralized utility or regulatory commission.
- The model shows that a competitive market will not have much over allocation of capacity. Aggregation techniques will eliminate a lot of excess capacity.
- This type of competitive advantage in a competitive electricity market is conditional on the collection, analysis and optimization of large amounts of data. Much of the electricity market competition will be waged at the information level. Sophisticated and robust models will be necessary to implement optimal aggregation algorithms.

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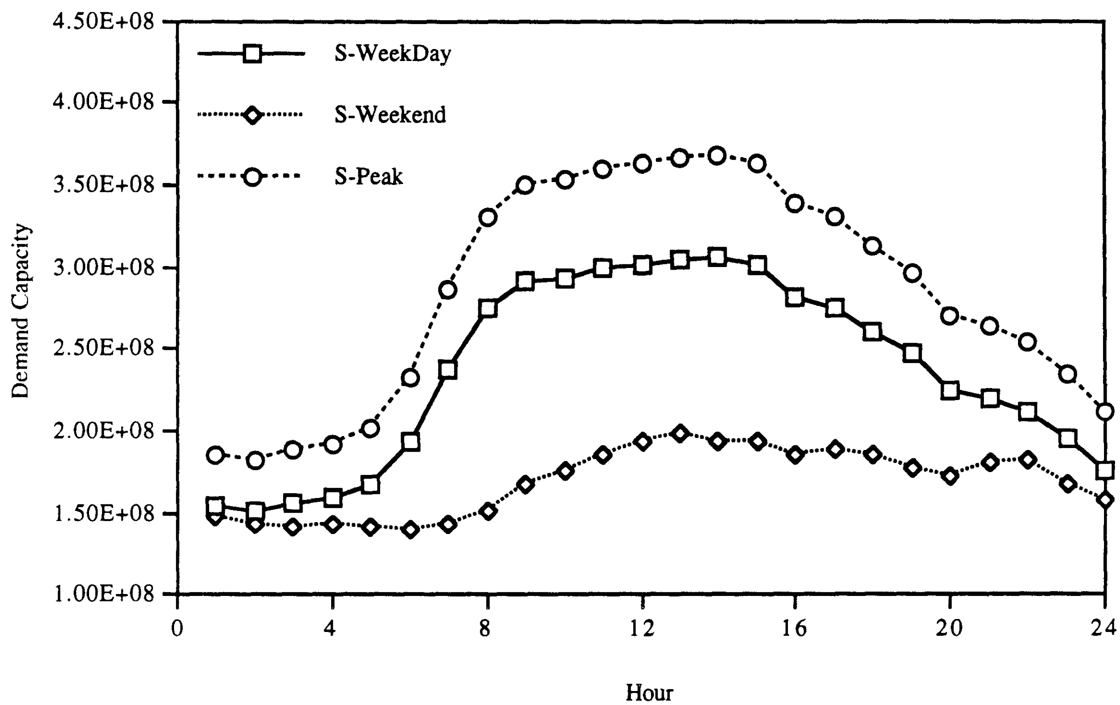
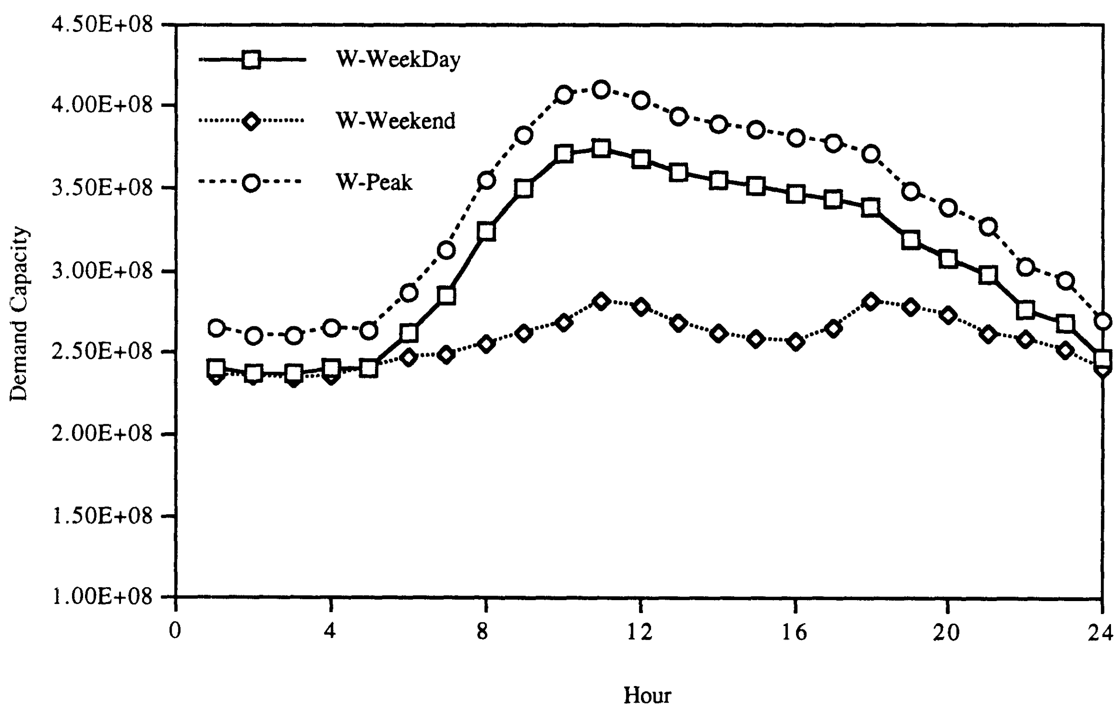
Appendix A: Consumer Load Profiles

Office

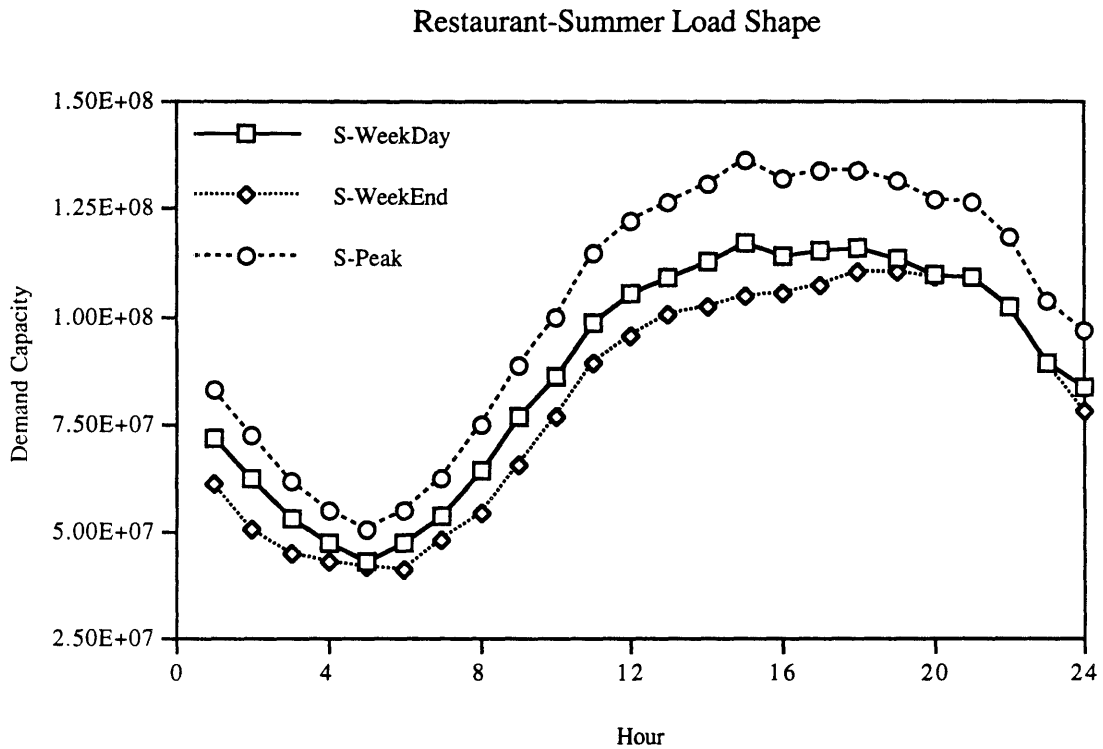
Office-Summer Load Shapes

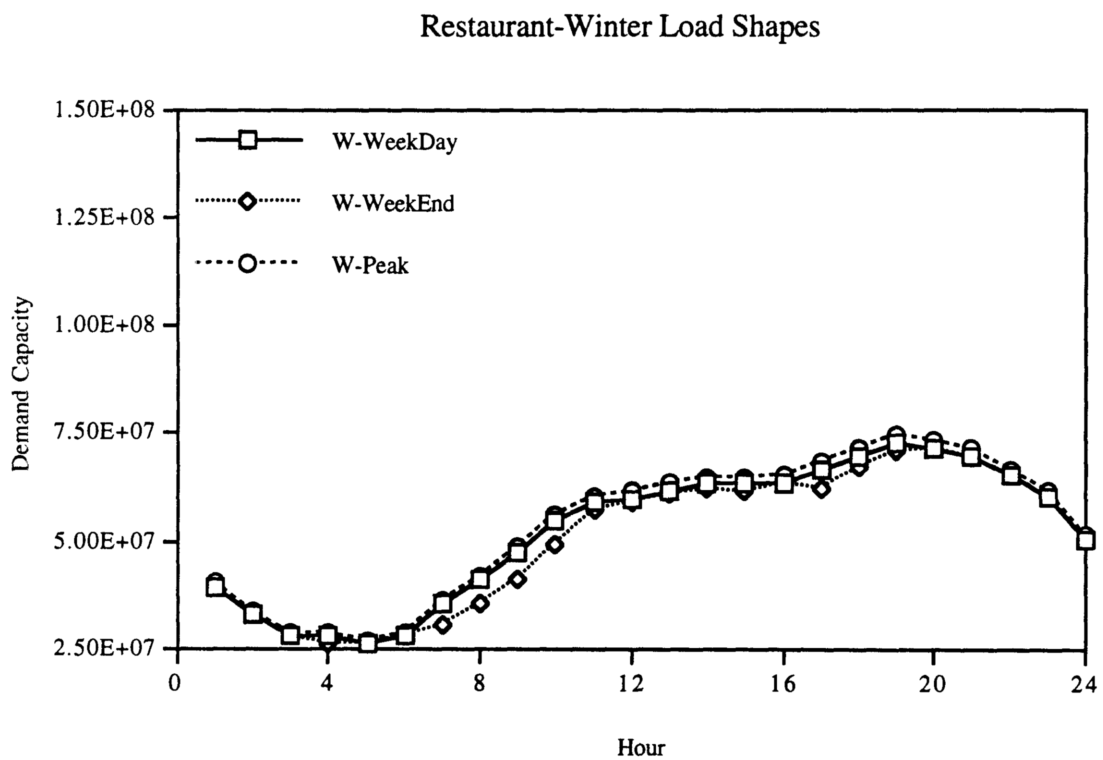


Office-Winter Load Shapes



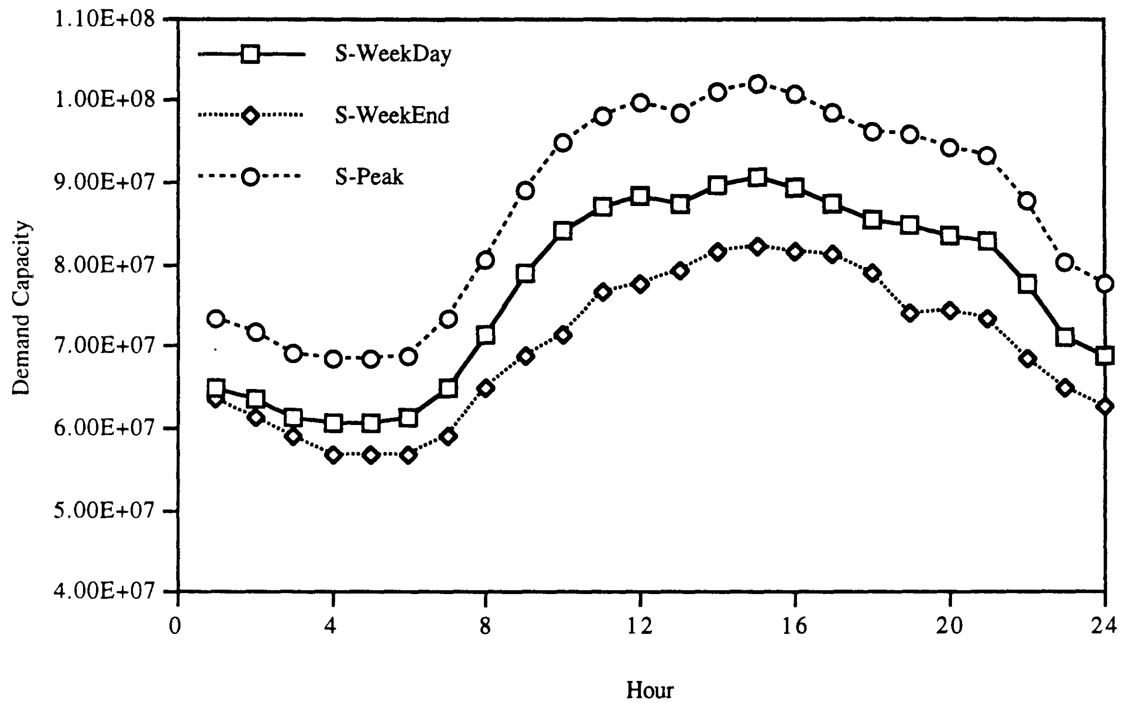
Restaurant


Restaurant-Summer Load Shape
1.50E+08
1.25E+08
1.00E+08
7.50E+07
5.00E+07
2.50E+07
Demand Capacity
S-WeekDay
S-WeekEnd
S-Peak
0
4
8
12
16
20
24
Hour

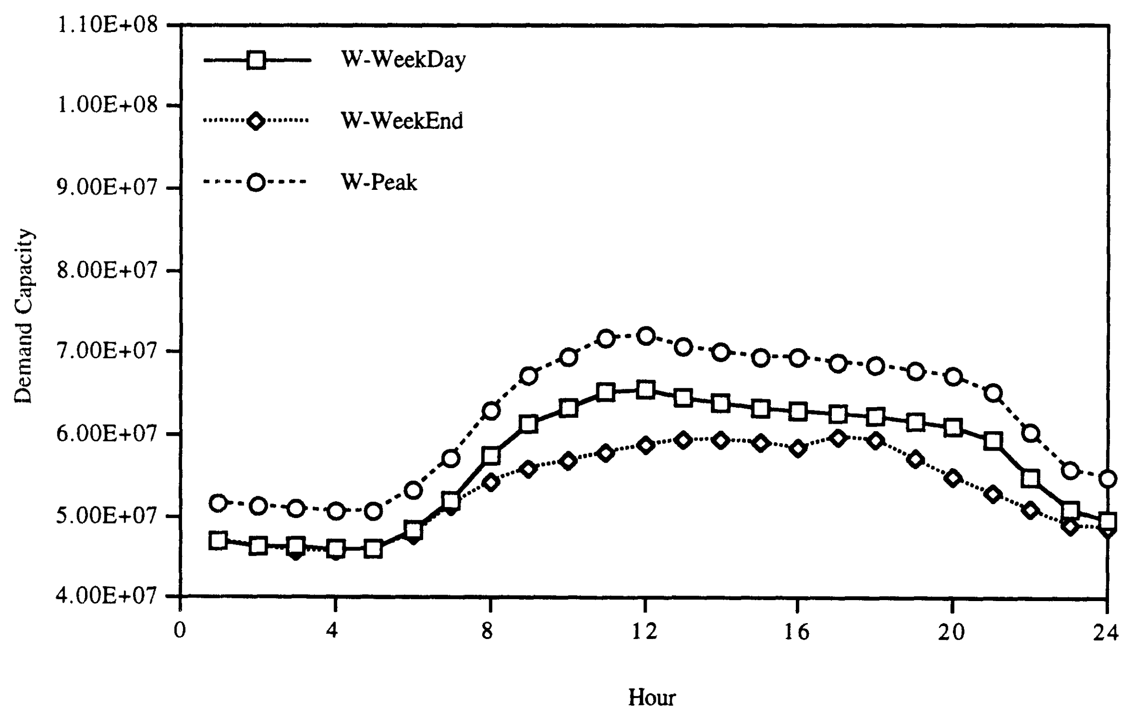

Restaurant-Winter Load Shapes
1.50E+08
1.25E+08
1.00E+08
7.50E+07
5.00E+07
2.50E+07
Demand Capacity
W-WeekDay
W-WeekEnd
W-Peak
0
4
8
12
16
20
24
Hour

Groceries

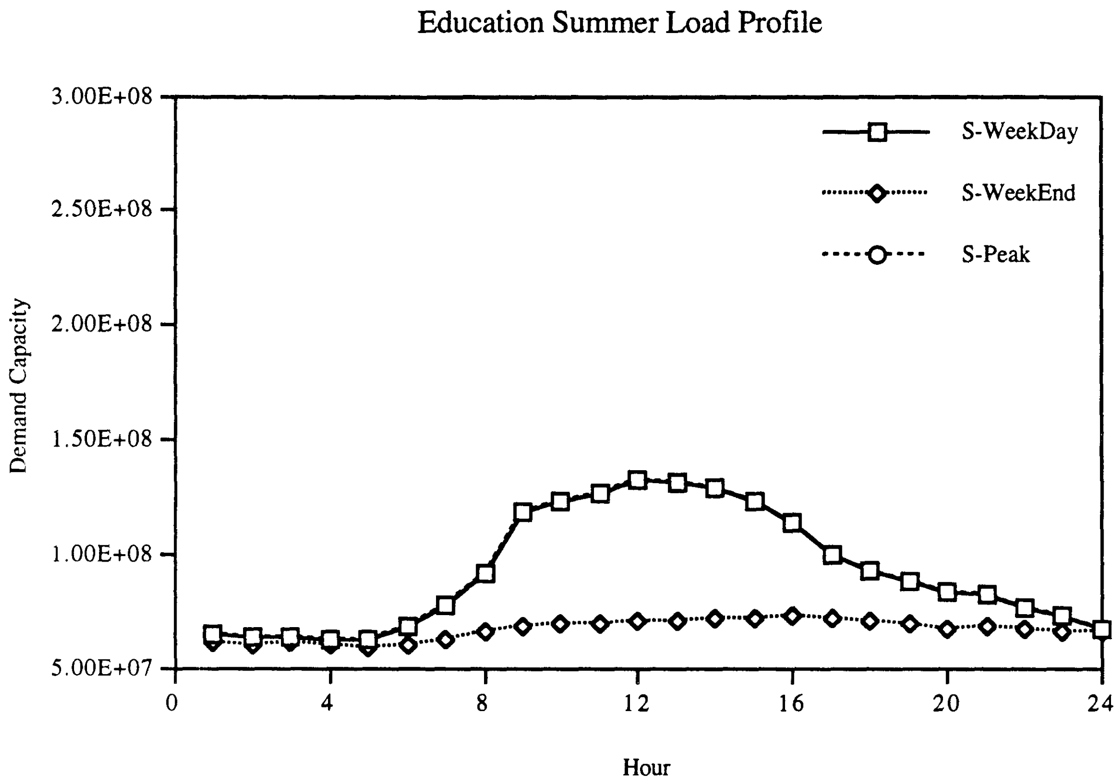
Groceries-Summer Load Shape



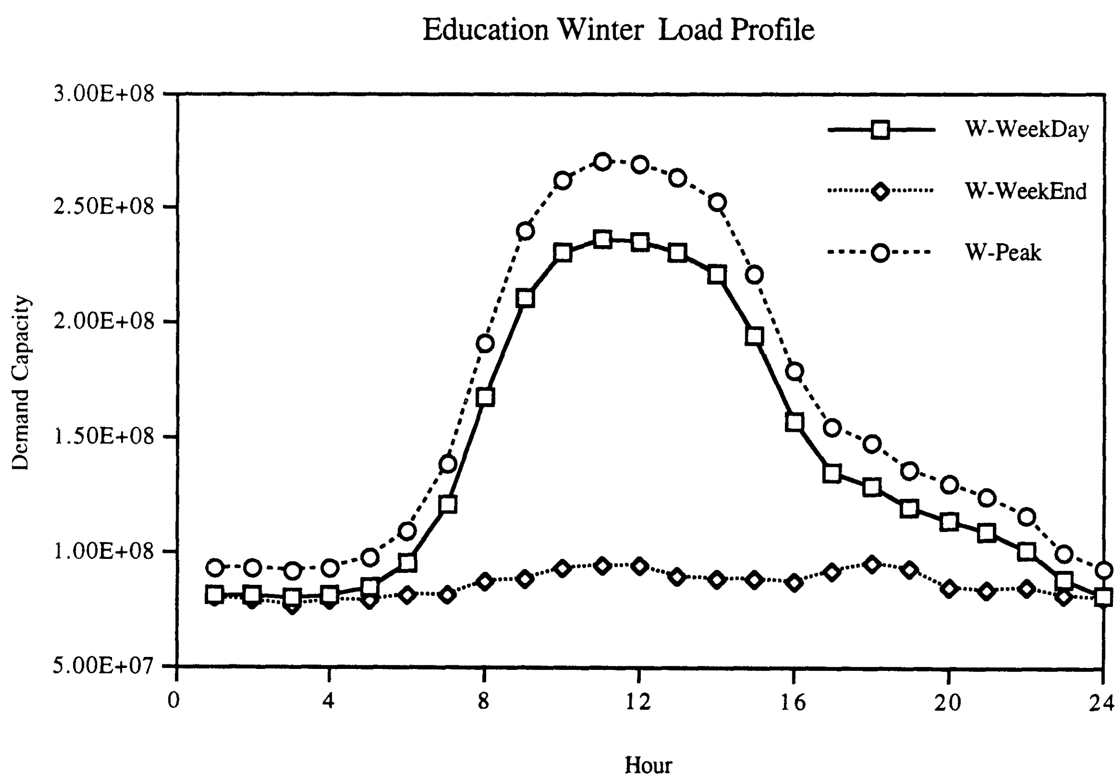
Groceries-Winter Load Shapes



Education

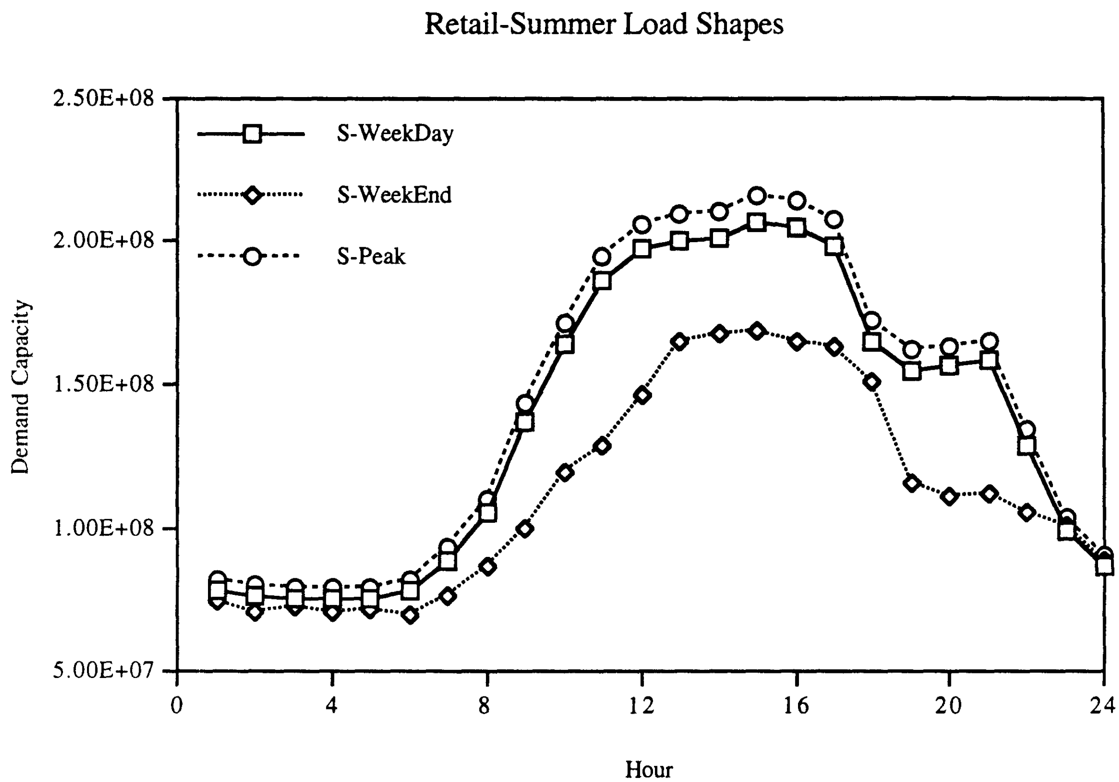


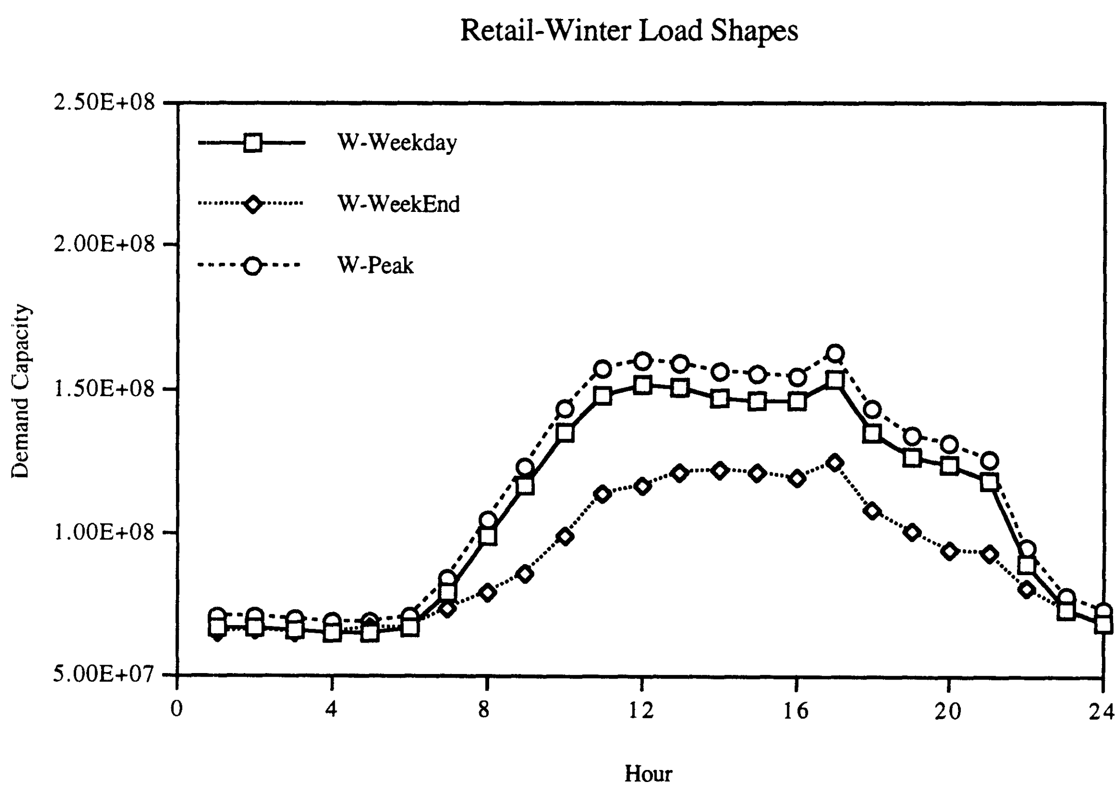
Education Summer Load Profile
3.00E+08
2.50E+08
2.00E+08
1.50E+08
1.00E+08
5.00E+07
Demand Capacity
0
4
8
12
16
20
24
Hour
S-WeekDay
S-WeekEnd
S-Peak



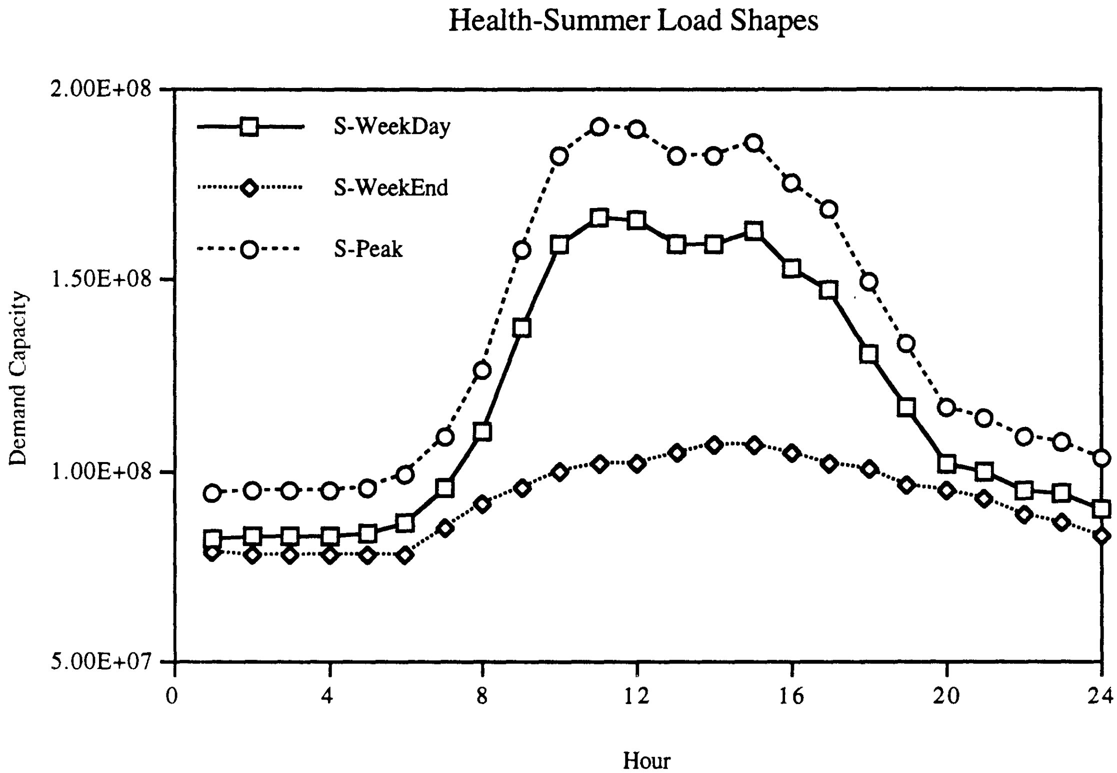
Education Winter Load Profile
3.00E+08
2.50E+08
2.00E+08
1.50E+08
1.00E+08
5.00E+07
Demand Capacity
0
4
8
12
16
20
24
Hour
W-WeekDay
W-WeekEnd
W-Peak

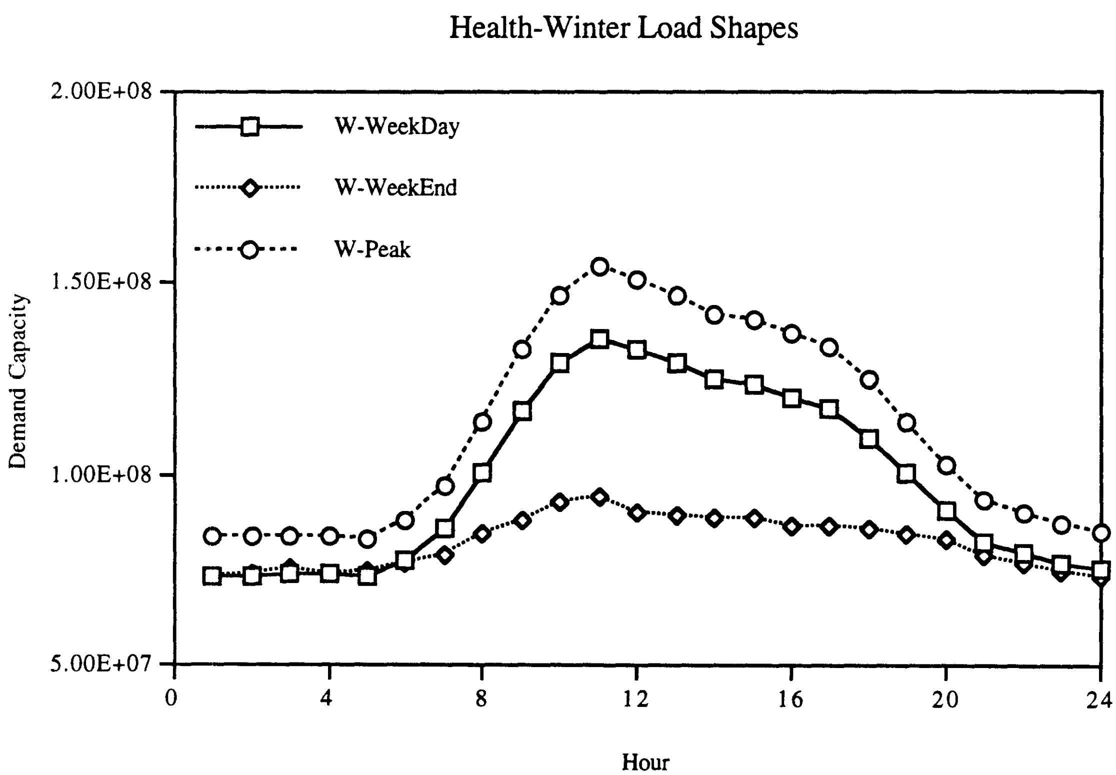
Retail


Retail-Summer Load Shapes
2.50E+08
2.00E+08
1.50E+08
1.00E+08
5.00E+07
Demand Capacity
0
4
8
12
16
20
24
Hour
S-WeekDay
S-WeekEnd
S-Peak

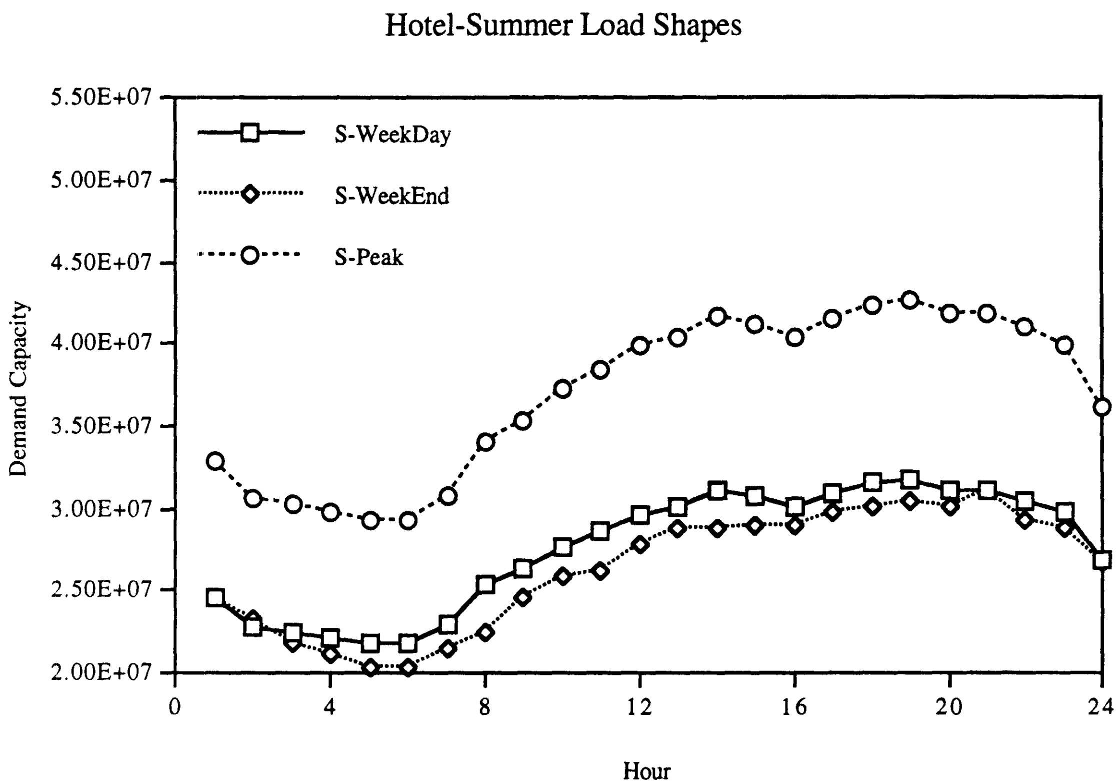

Retail-Winter Load Shapes
2.50E+08
2.00E+08
1.50E+08
1.00E+08
5.00E+07
Demand Capacity
0
4
8
12
16
20
24
Hour
W-Weekday
W-WeekEnd
W-Peak

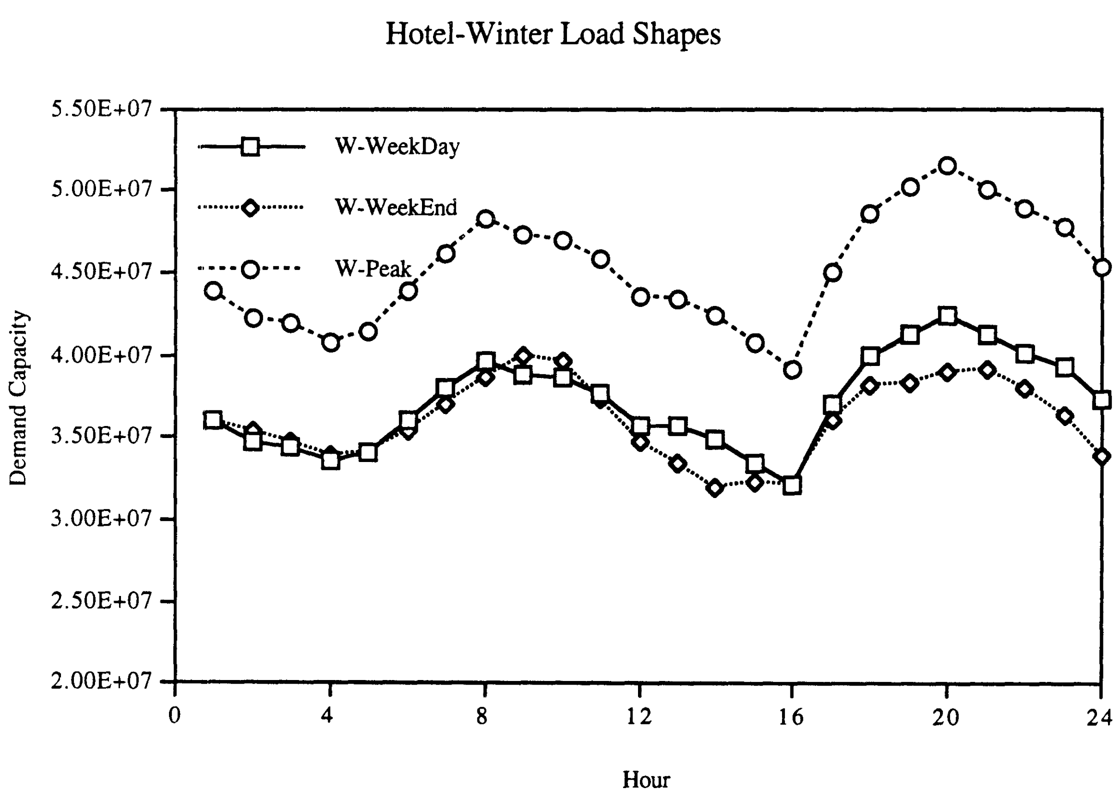
Health


Health-Summer Load Shapes
2.00E+08
1.50E+08
1.00E+08
5.00E+07
Demand Capacity
S-WeekDay
S-WeekEnd
S-Peak
0
4
8
12
16
20
24
Hour

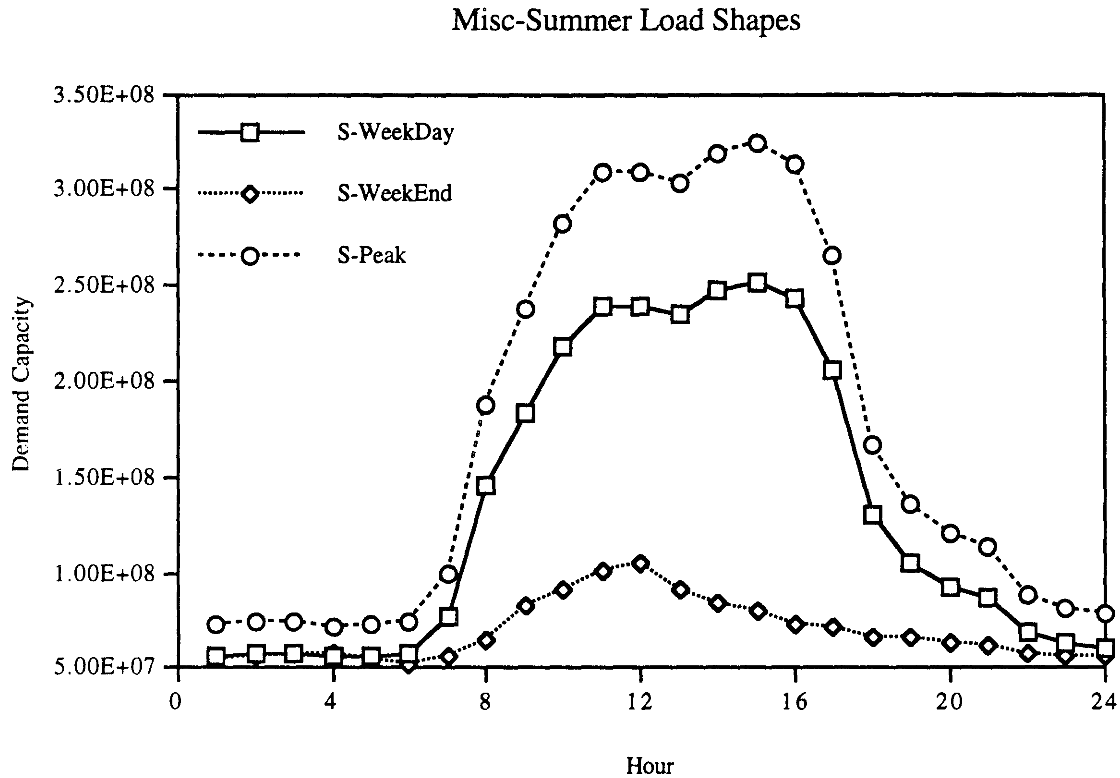

Health-Winter Load Shapes
2.00E+08
1.50E+08
1.00E+08
5.00E+07
Demand Capacity
W-WeekDay
W-WeekEnd
W-Peak
0
4
8
12
16
20
24
Hour

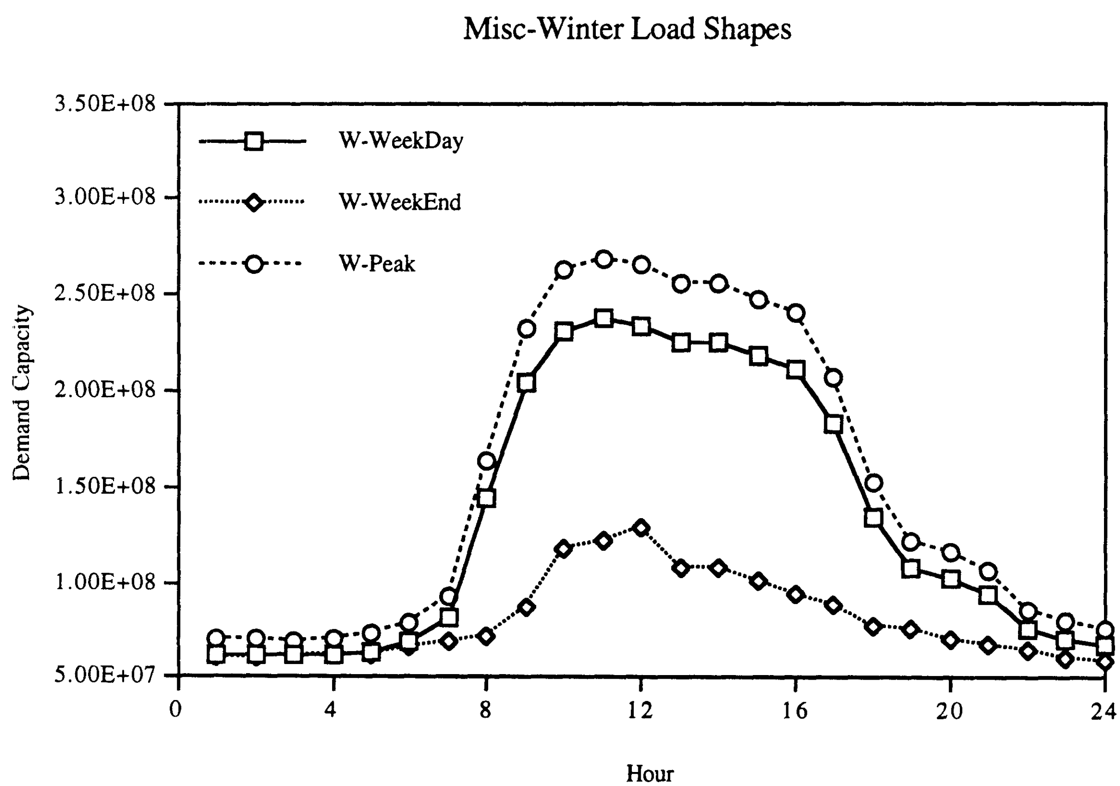
Hotel


Hotel-Summer Load Shapes
S-WeekDay
S-WeekEnd
S-Peak
Demand Capacity
5.50E+07
5.00E+07
4.50E+07
4.00E+07
3.50E+07
3.00E+07
2.50E+07
2.00E+07
0
4
8
12
16
20
24
Hour


Hotel-Winter Load Shapes
W-WeekDay
W-WeekEnd
W-Peak
Demand Capacity
5.50E+07
5.00E+07
4.50E+07
4.00E+07
3.50E+07
3.00E+07
2.50E+07
2.00E+07
0
4
8
12
16
20
24
Hour

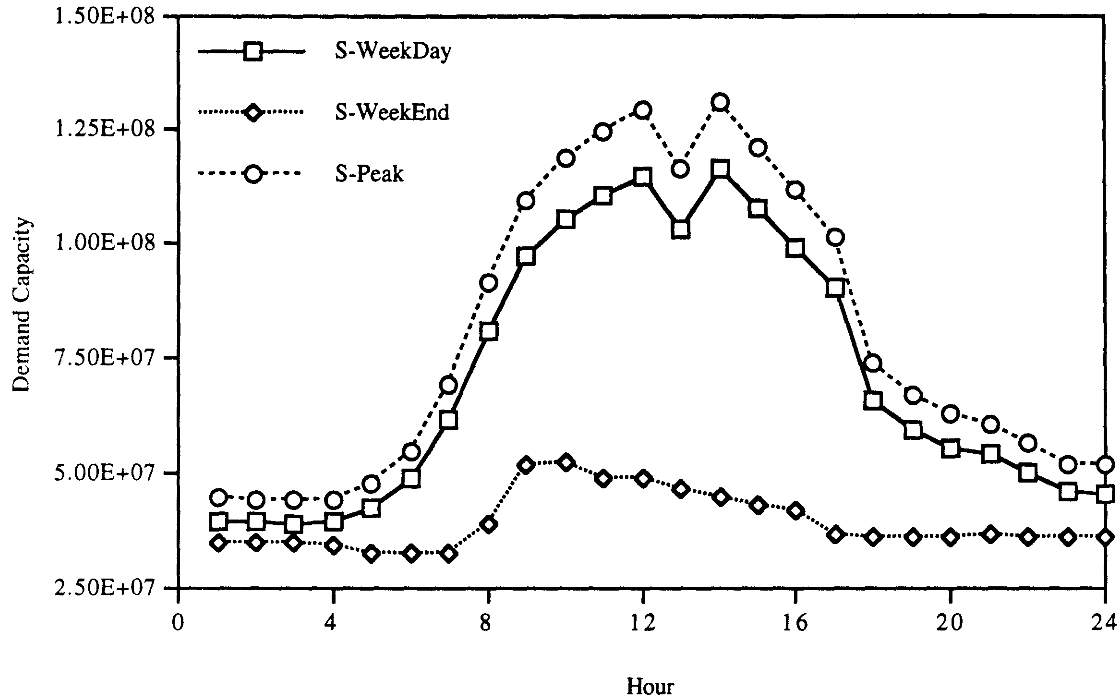
Misc


Misc-Summer Load Shapes
S-WeekDay
S-WeekEnd
S-Peak
Demand Capacity
3.50E+08
3.00E+08
2.50E+08
2.00E+08
1.50E+08
1.00E+08
5.00E+07
0
4
8
12
16
20
24
Hour

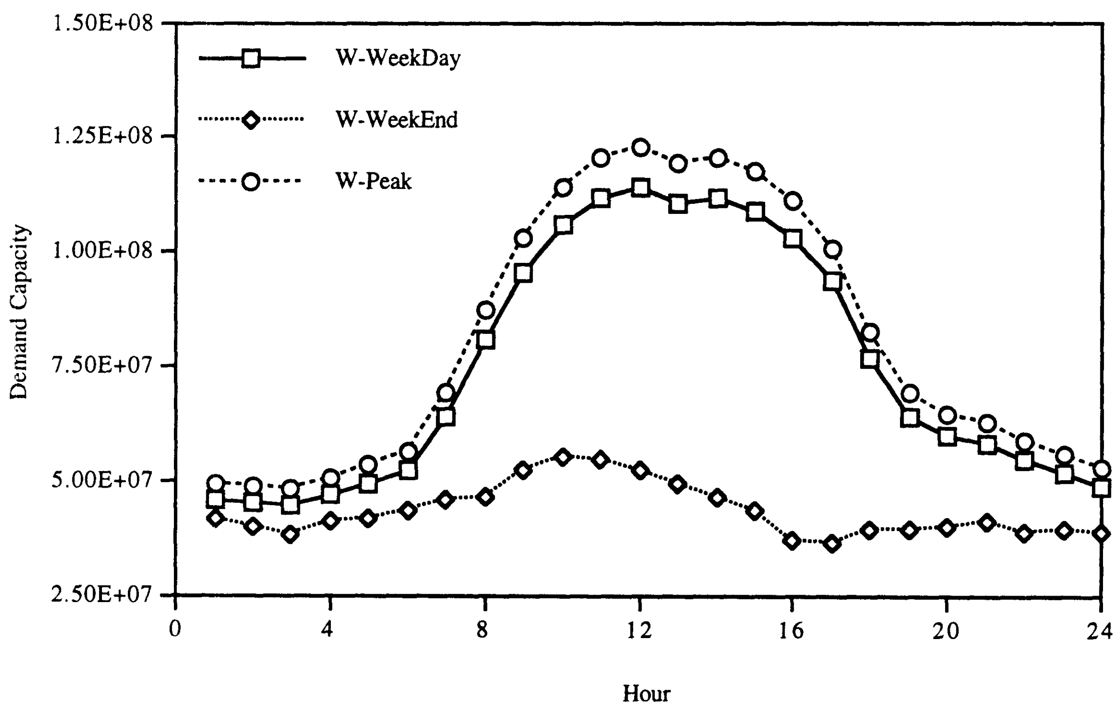

Misc-Winter Load Shapes
W-WeekDay
W-WeekEnd
W-Peak
Demand Capacity
3.50E+08
3.00E+08
2.50E+08
2.00E+08
1.50E+08
1.00E+08
5.00E+07
0
4
8
12
16
20
24
Hour

Warehouse

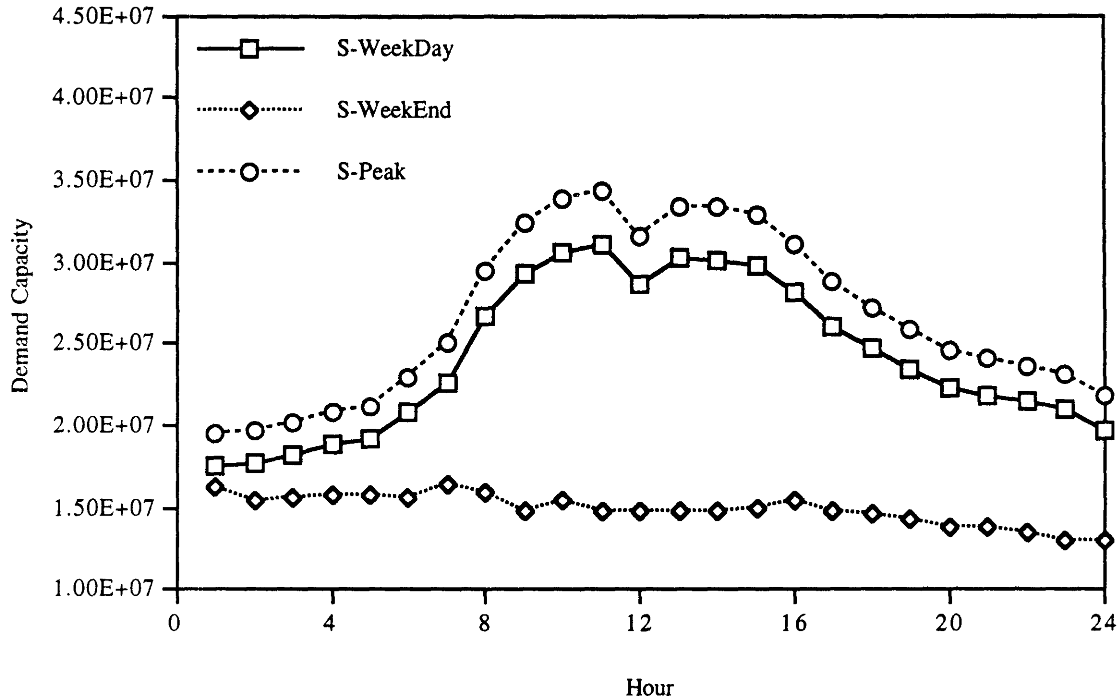
Warehouse-Summer Load Shapes



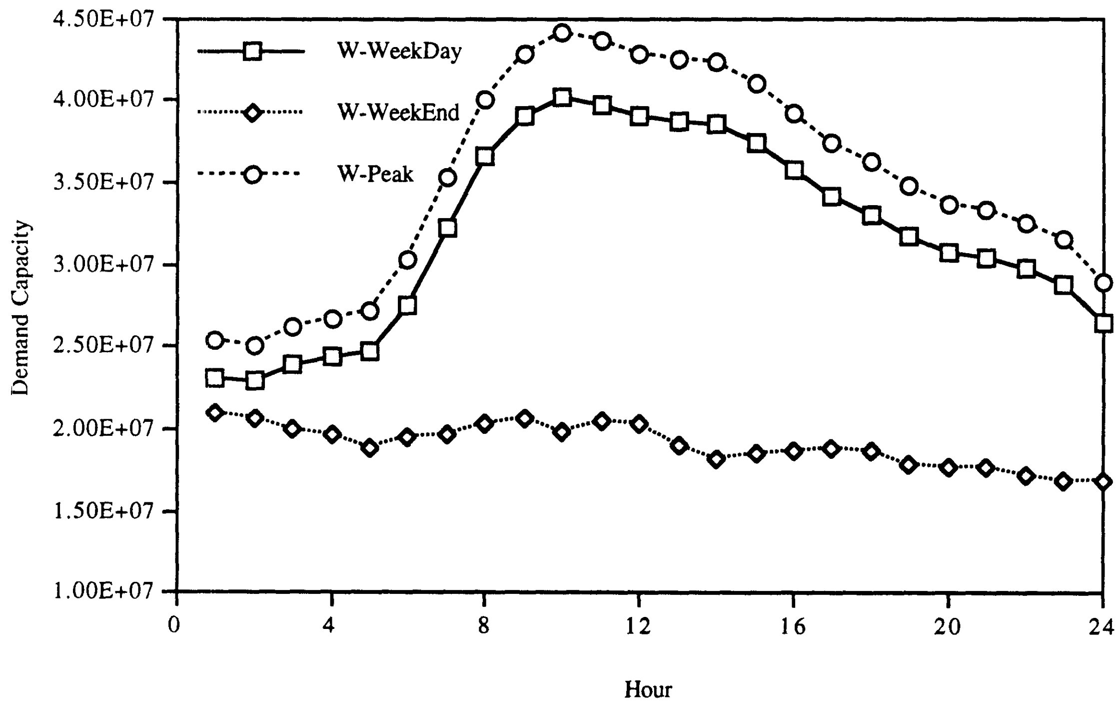
Warehouse-Winter Load Shapes



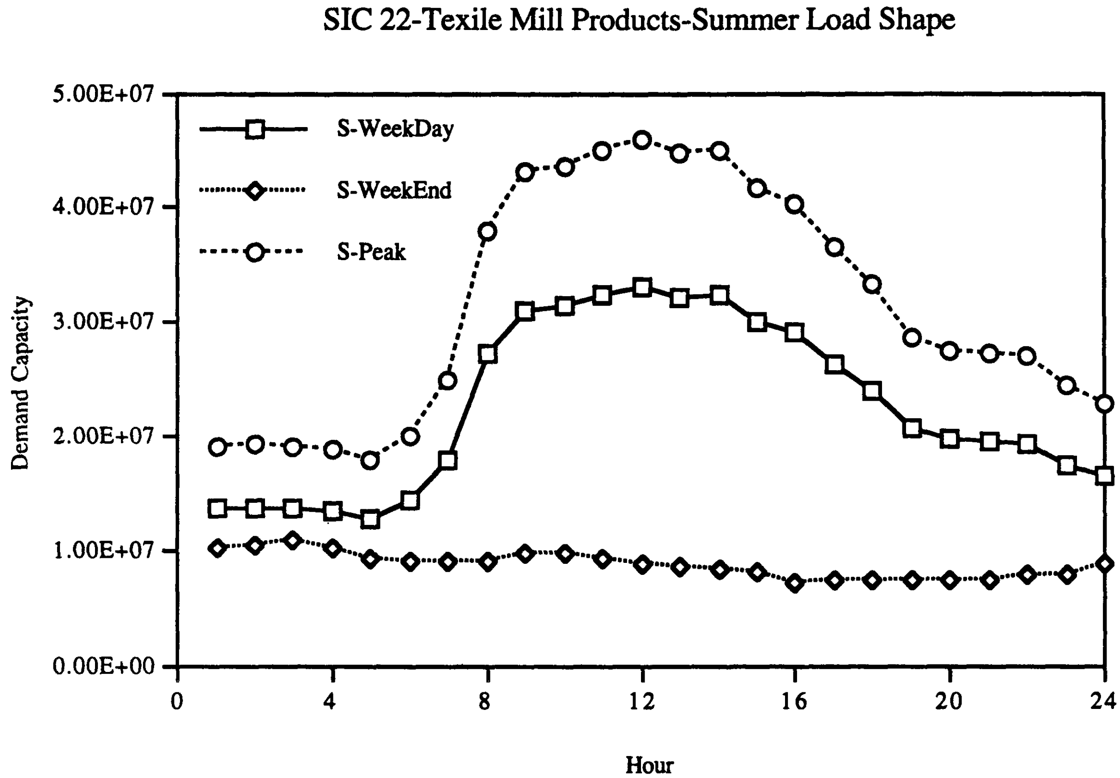
Food (SIC20)

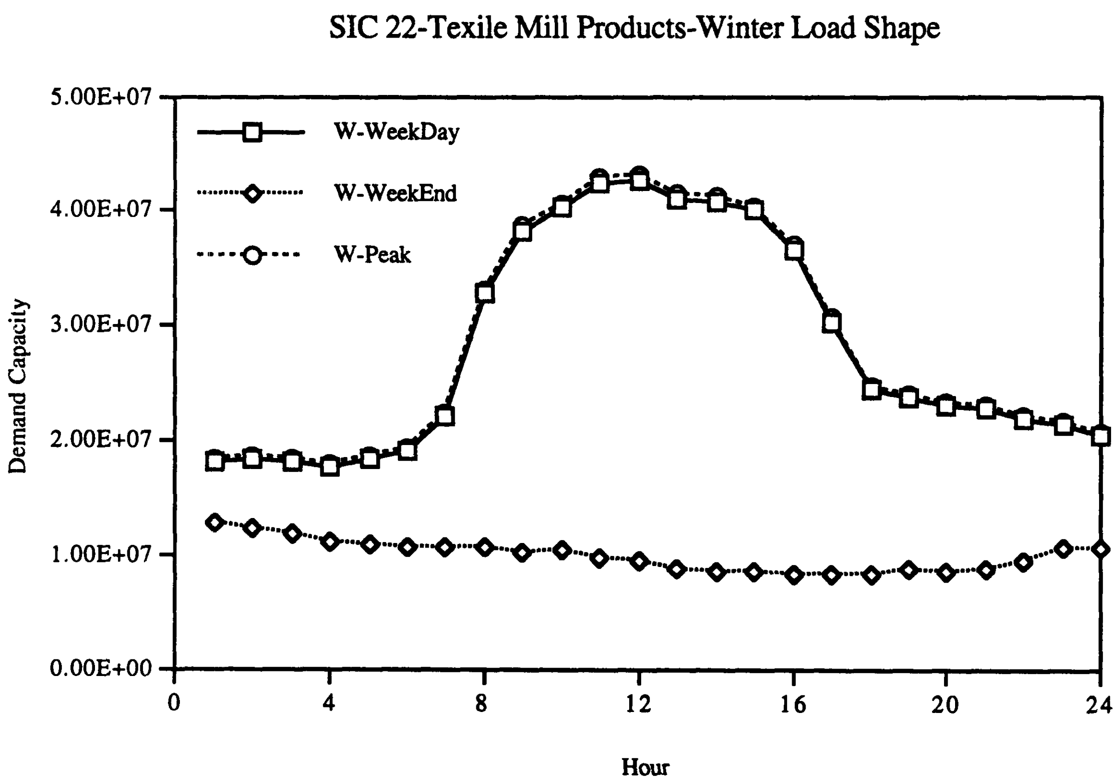


SIC 20-Food and Kindred Products-Winter Load Shapes

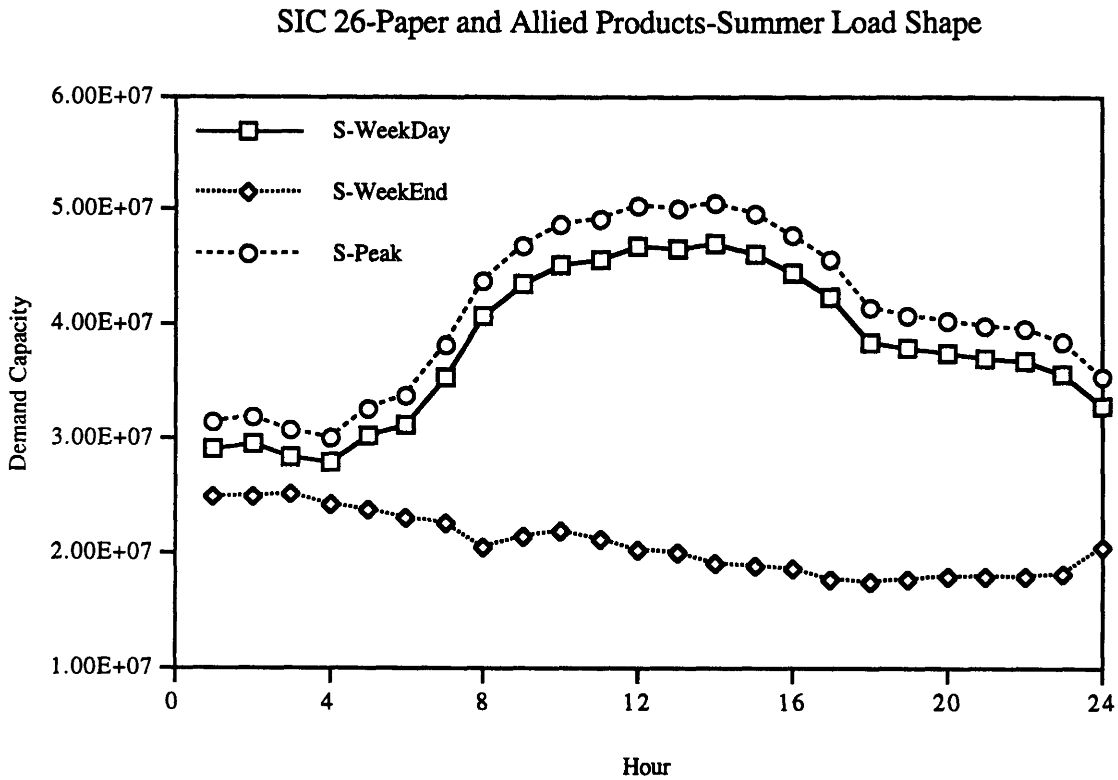


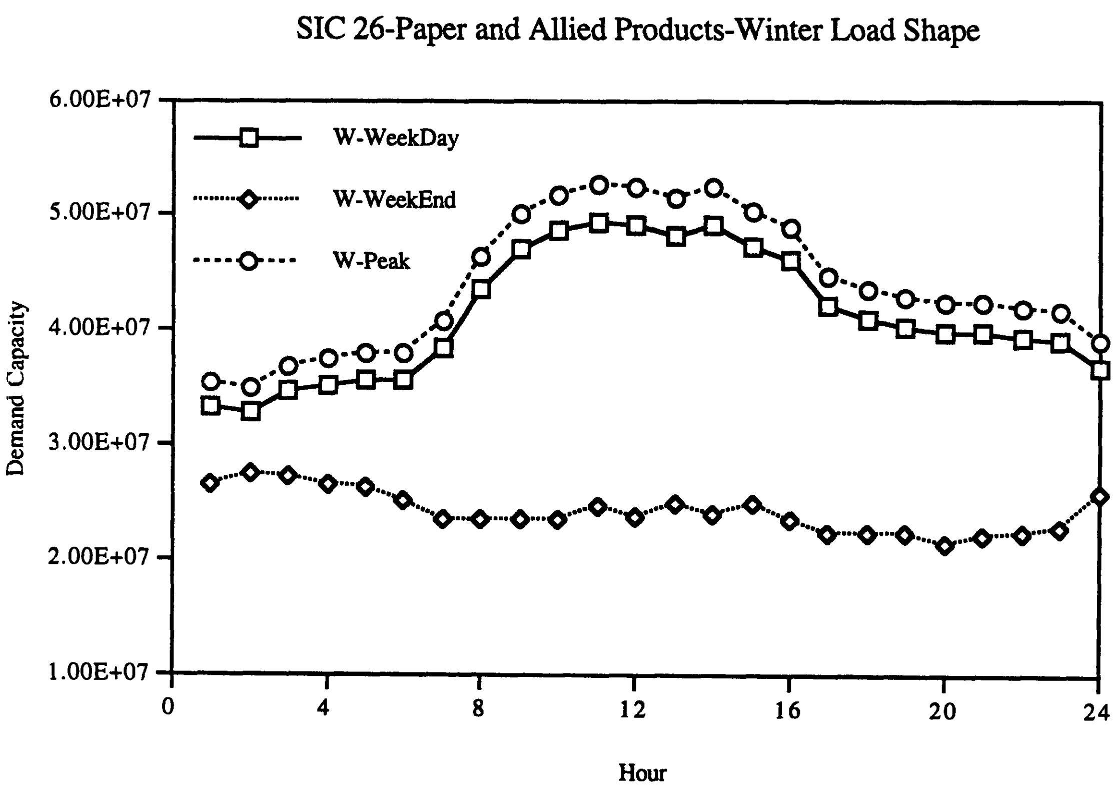
Text Mill (SIC 22)



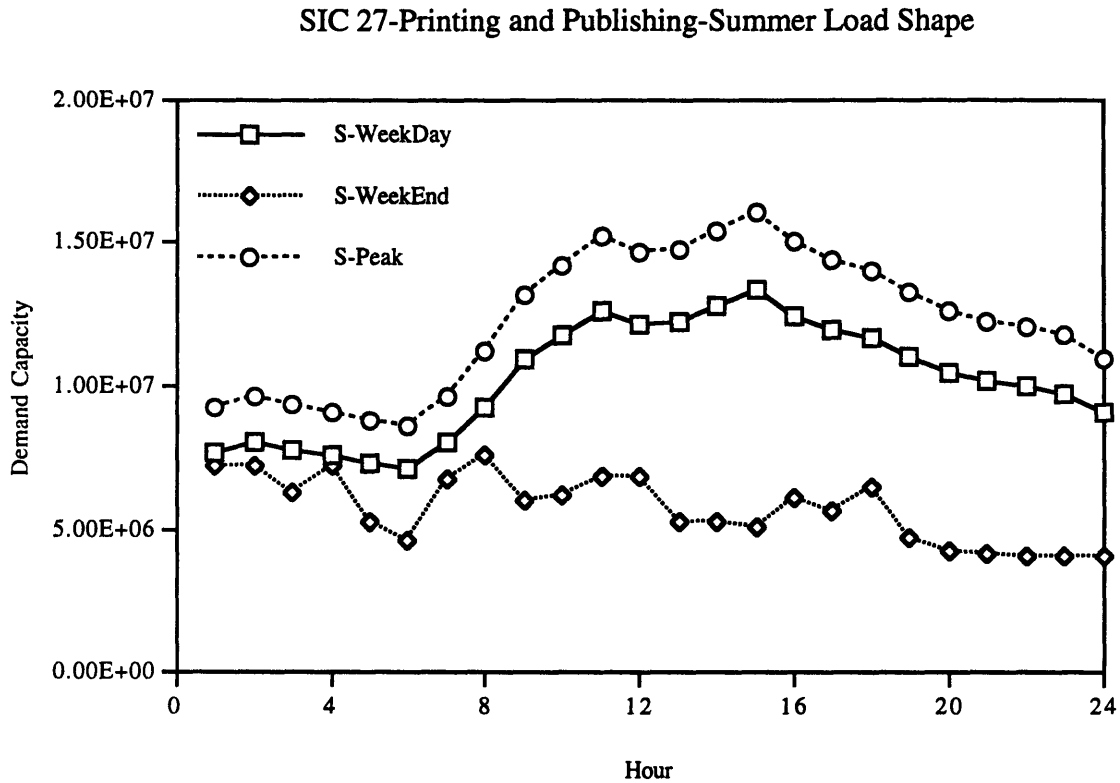


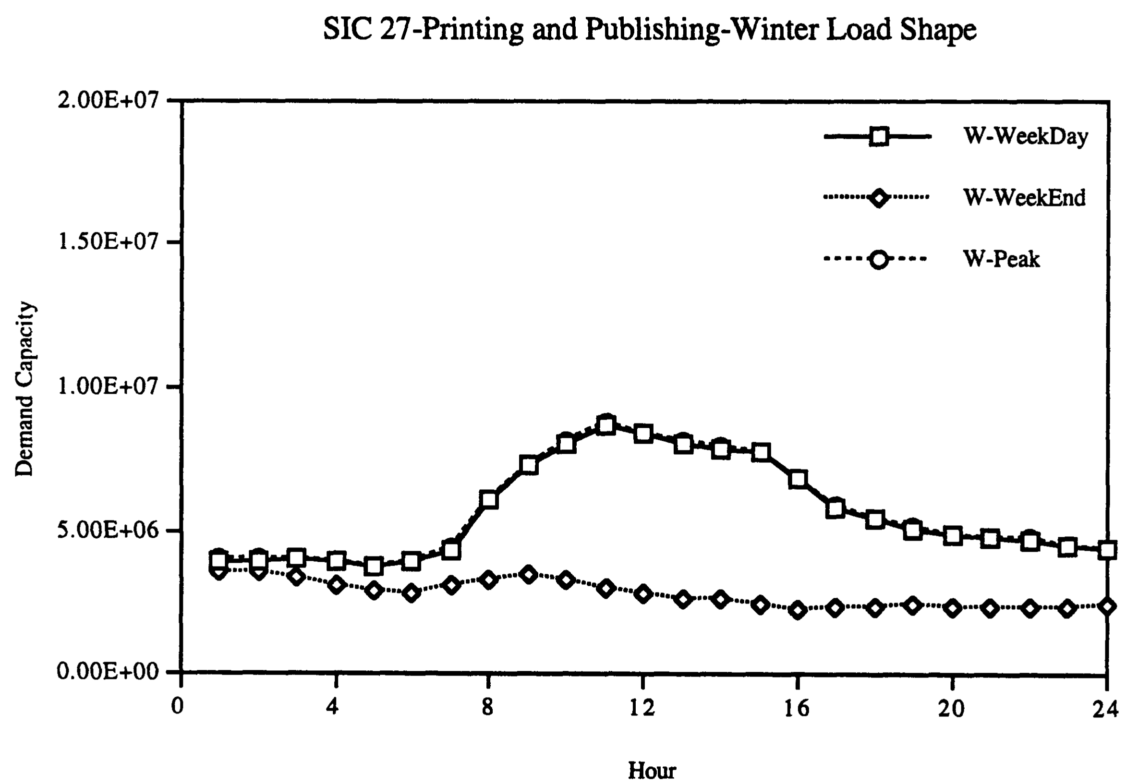
Paper (SIC 26)


SIC 26-Paper and Allied Products-Summer Load Shape
S-WeekDay
S-WeekEnd
S-Peak
Demand Capacity
6.00E+07
5.00E+07
4.00E+07
3.00E+07
2.00E+07
1.00E+07
0
4
8
12
16
20
24
Hour

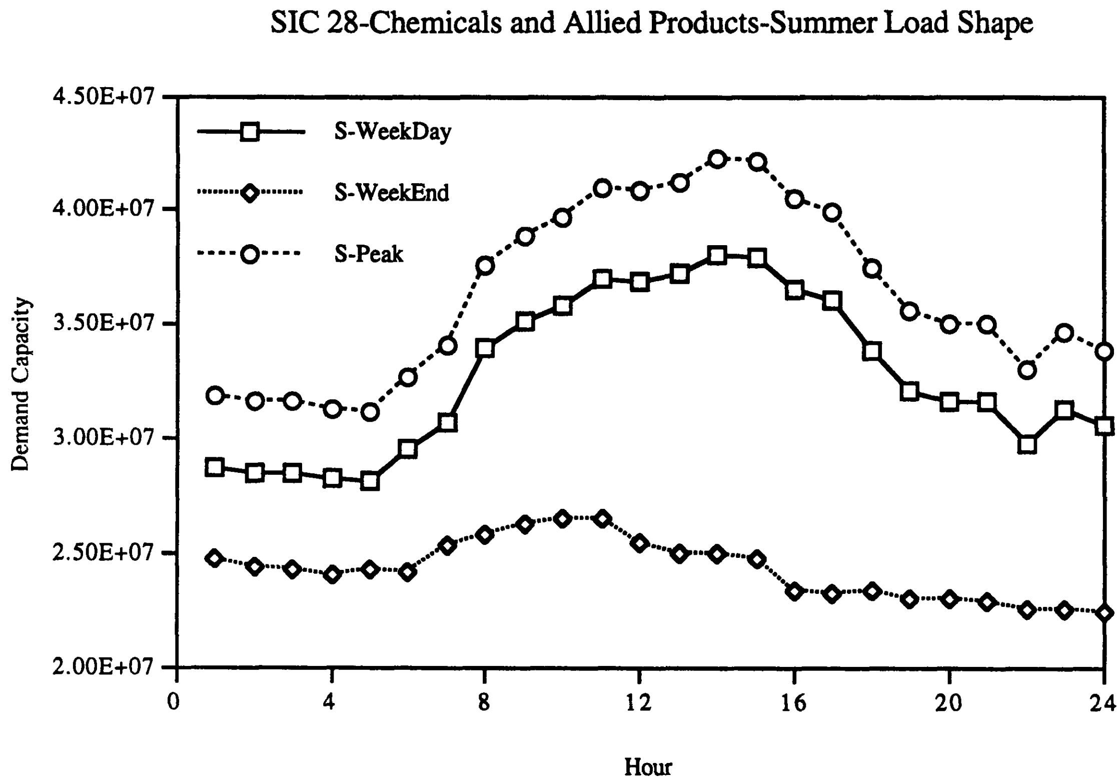

SIC 26-Paper and Allied Products-Winter Load Shape
W-WeekDay
W-WeekEnd
W-Peak
Demand Capacity
6.00E+07
5.00E+07
4.00E+07
3.00E+07
2.00E+07
1.00E+07
0
4
8
12
16
20
24
Hour

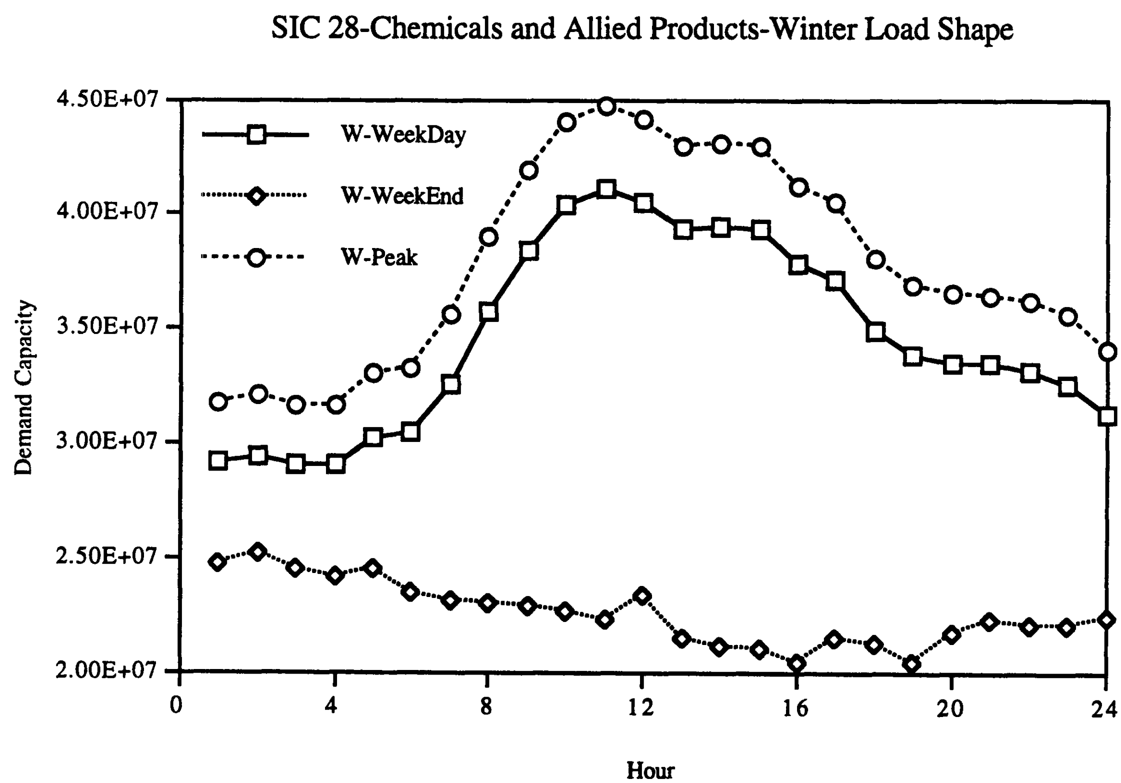
Printing (SIC 27)



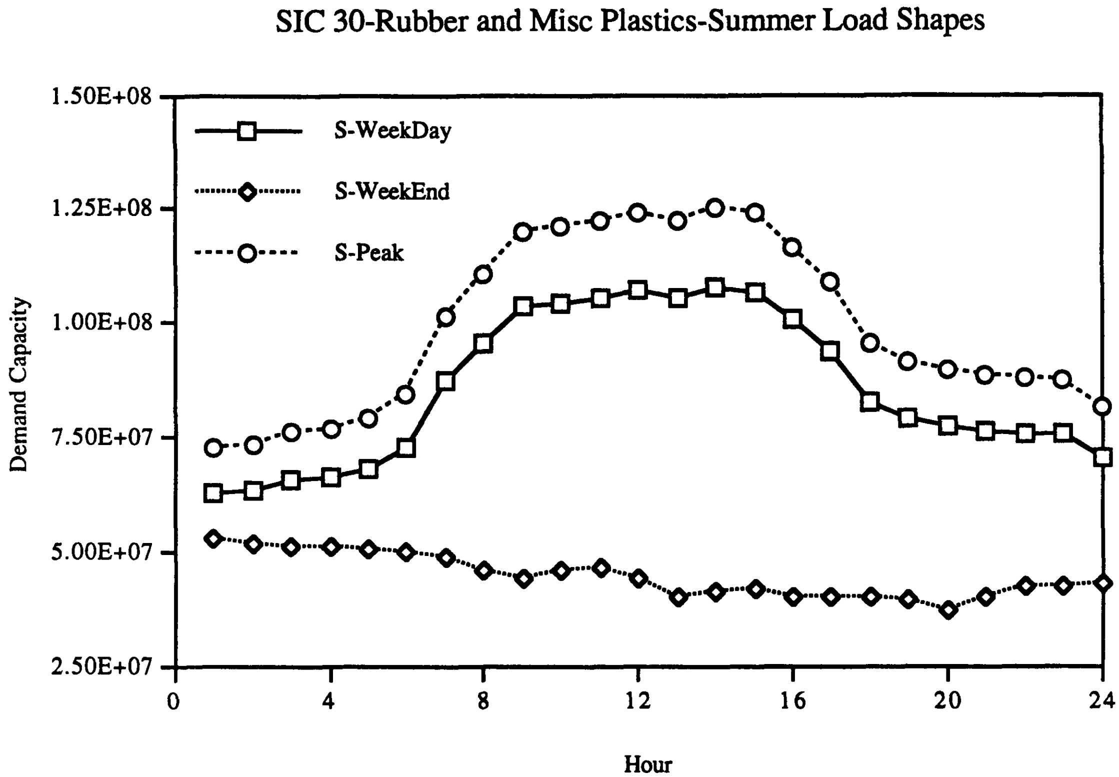


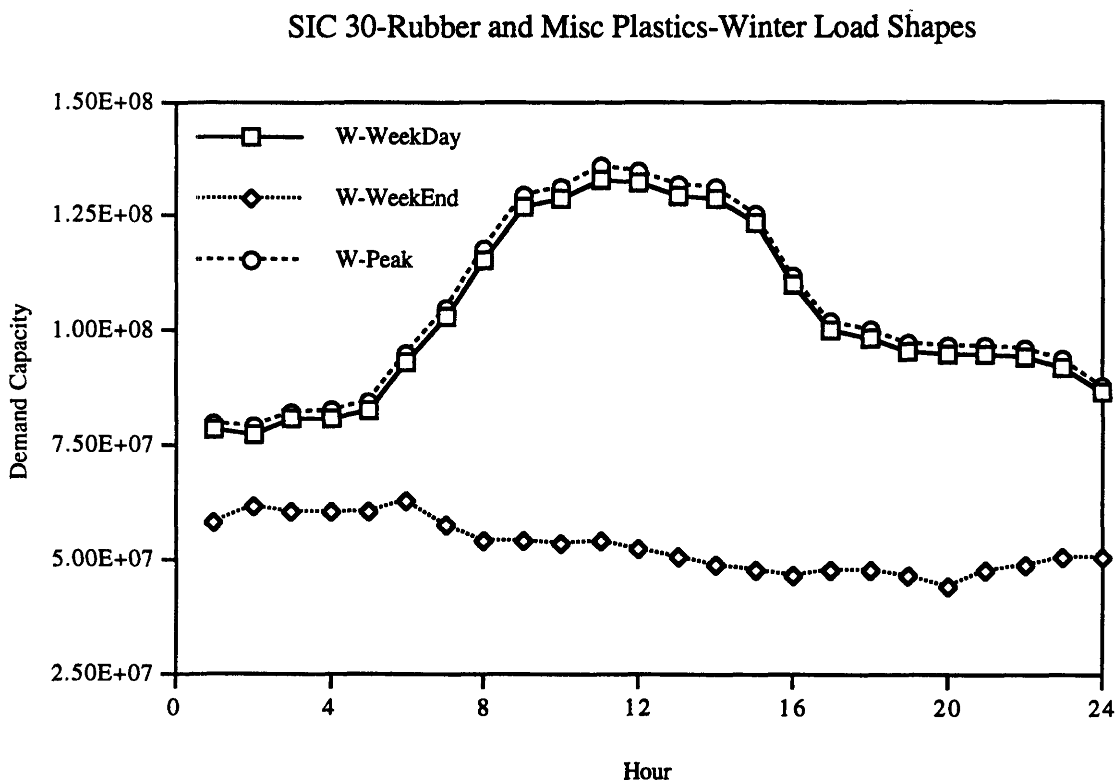
Chemicals (SIC 28)



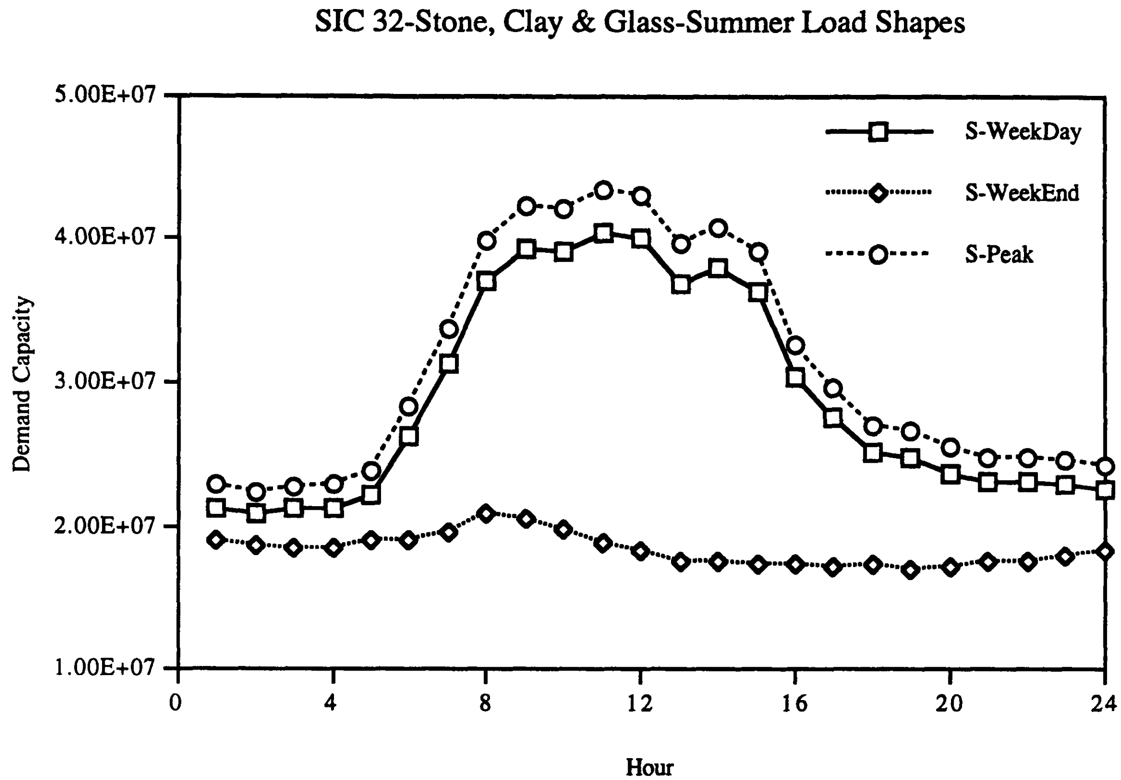


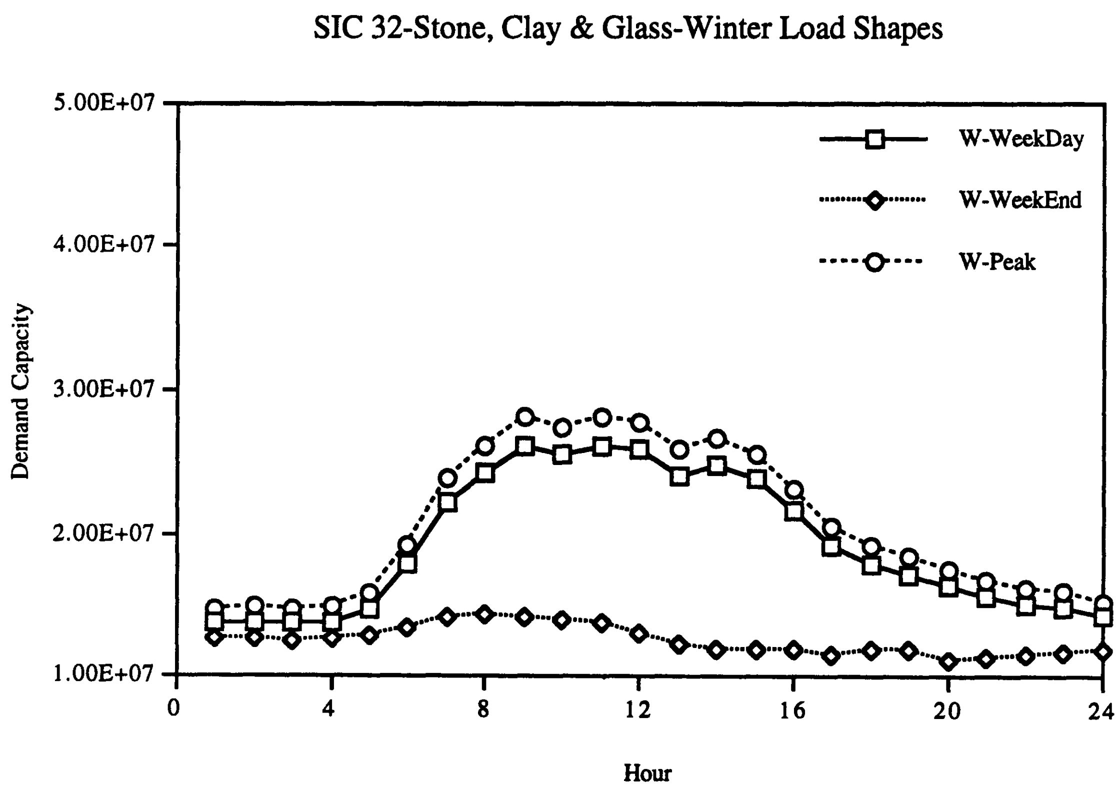
Rubber (SIC 30)



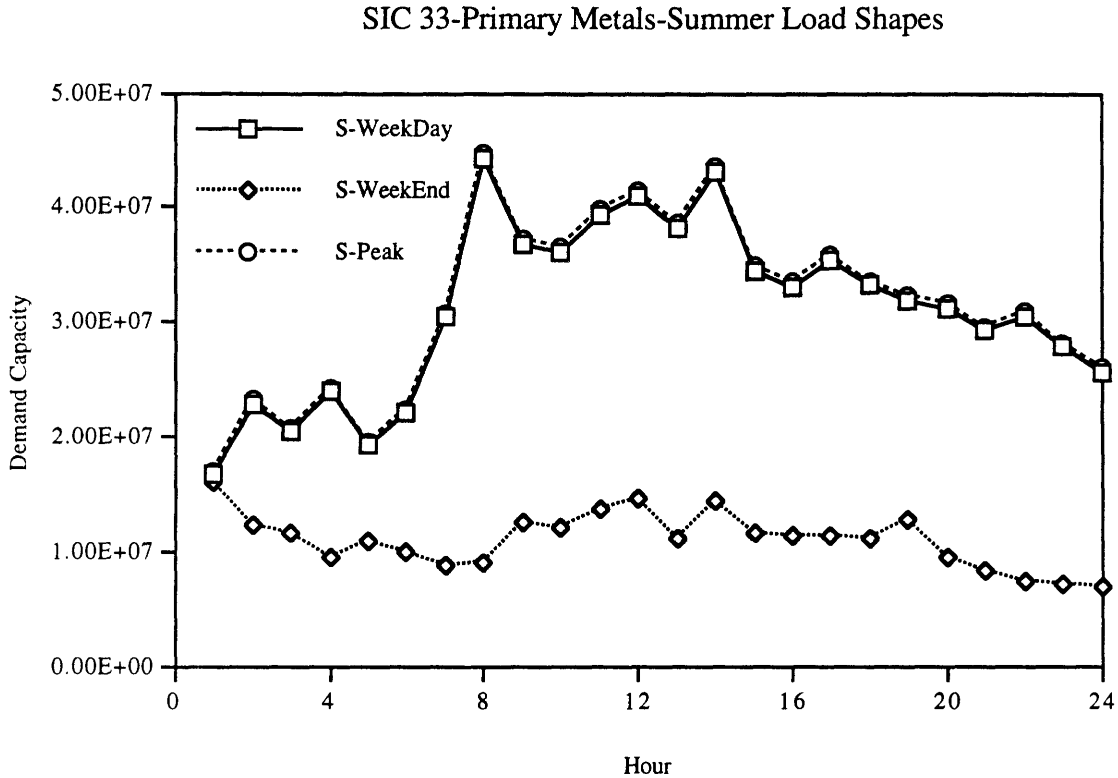


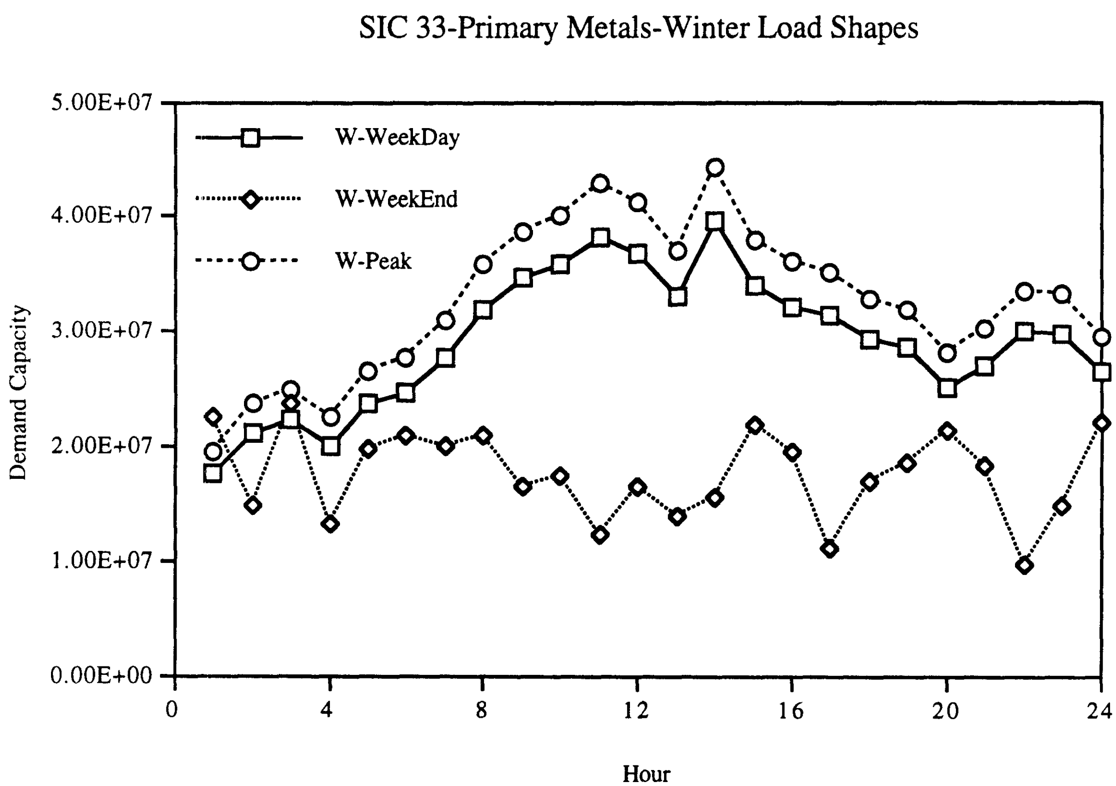
Stone, Clay and Glass (SIC 32)



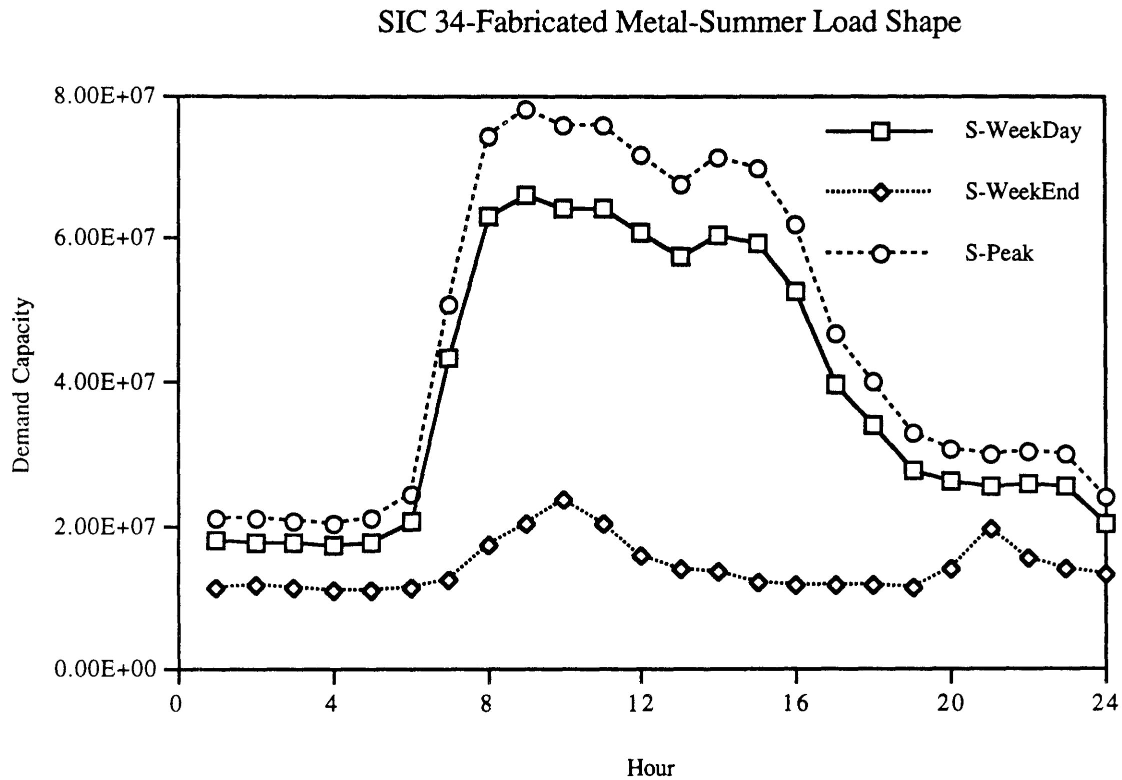


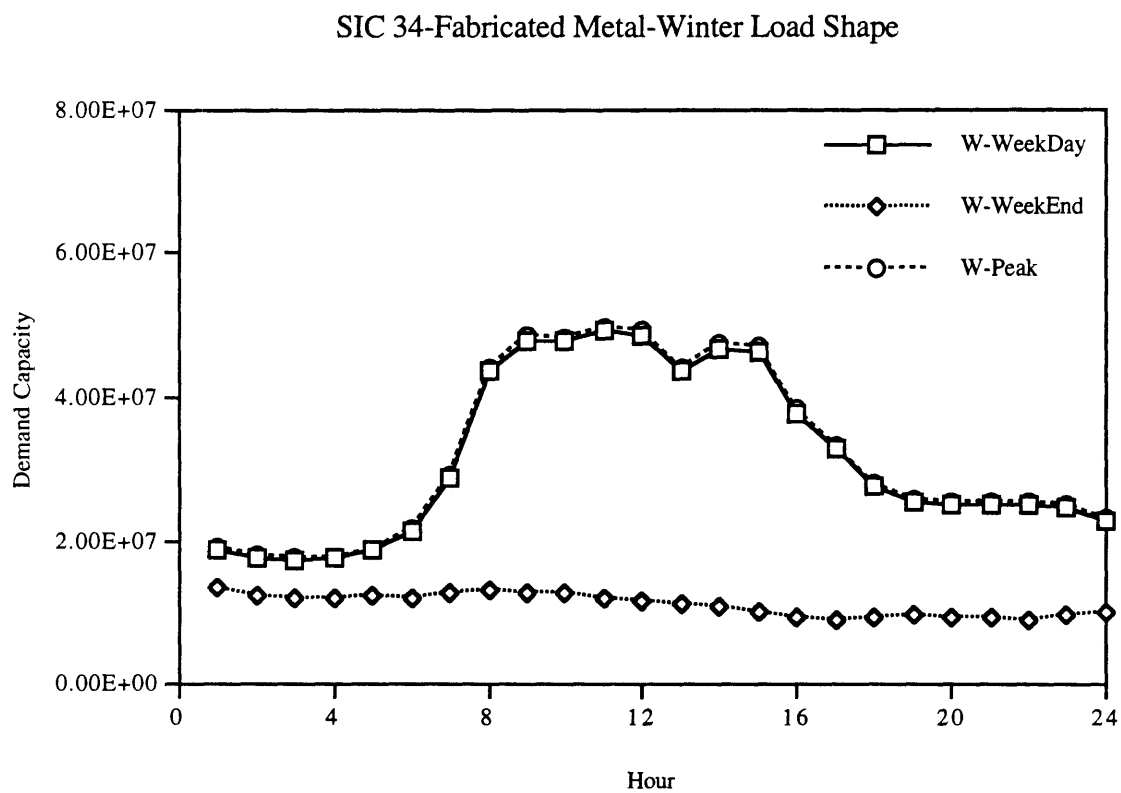
Primary Metal (SIC 33)





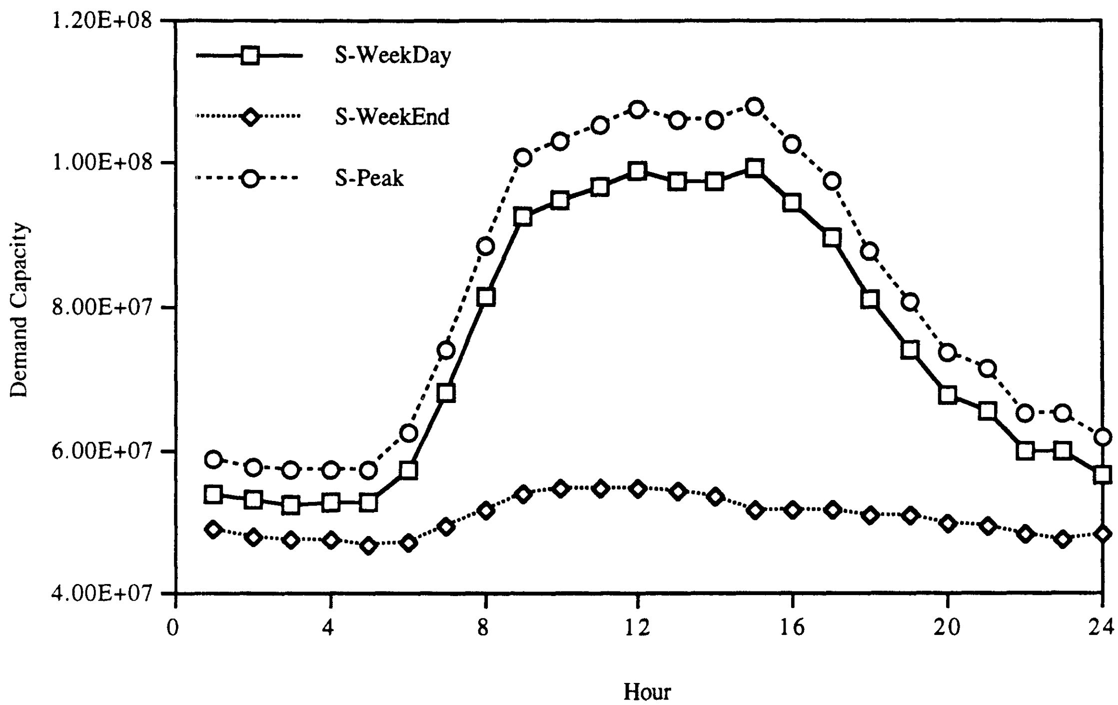
Fabricated Metal (SIC 34)



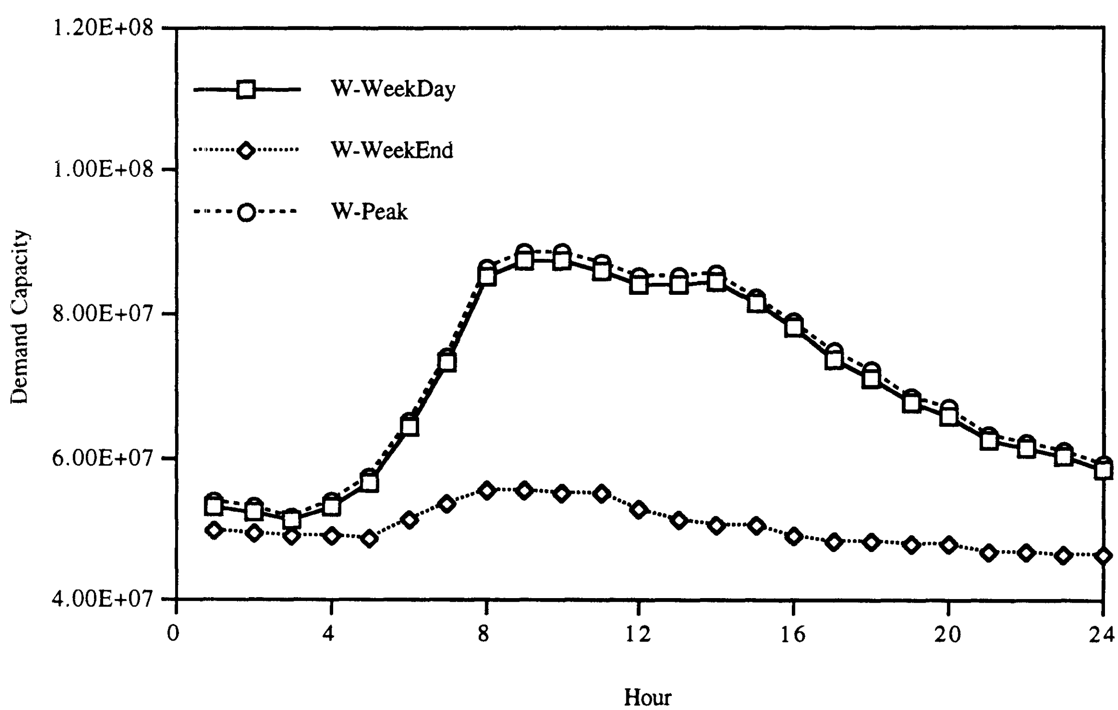


Industrial Machinery (SIC 35)

SIC 35-Industrial Machinery-Summer Load Shape

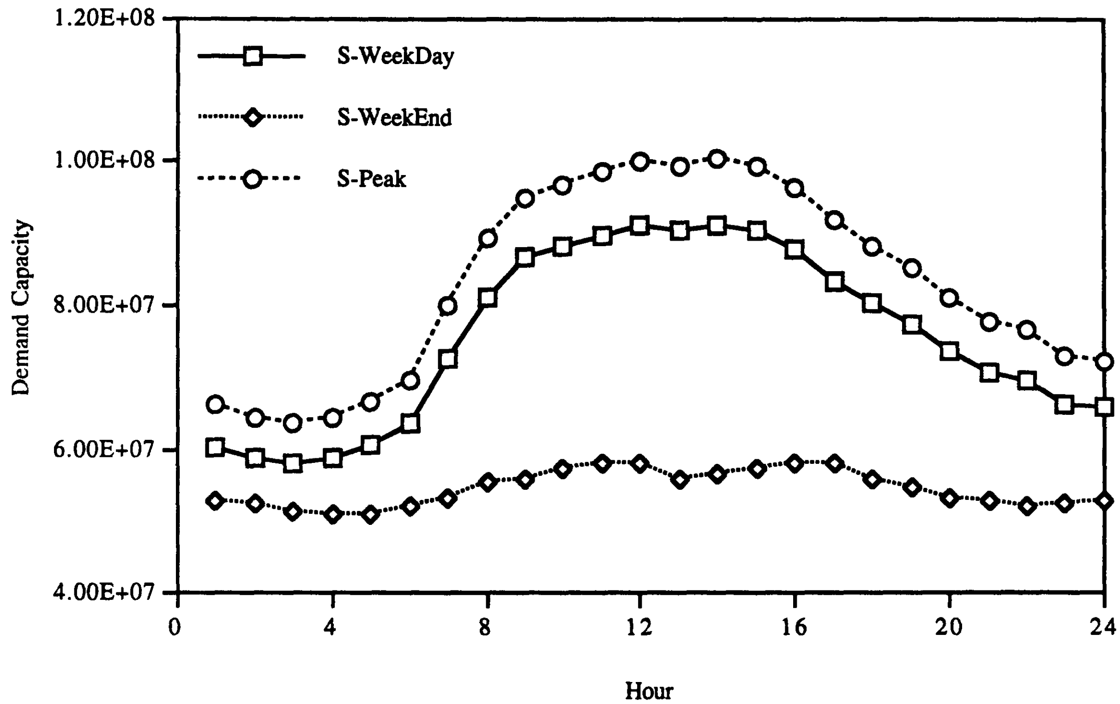


SIC 35-Industrial Machinery-Winter Load Shape

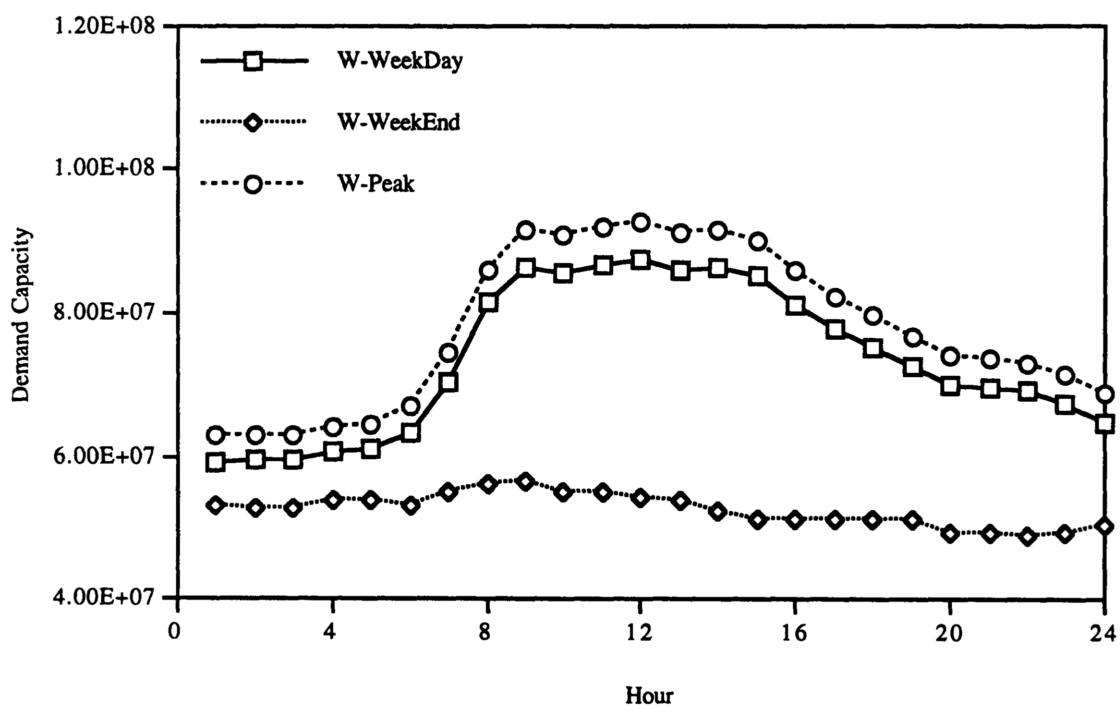


Electronic (SIC 36)

SIC 36-Electronic and Electric Equipment-Summer Load Shape

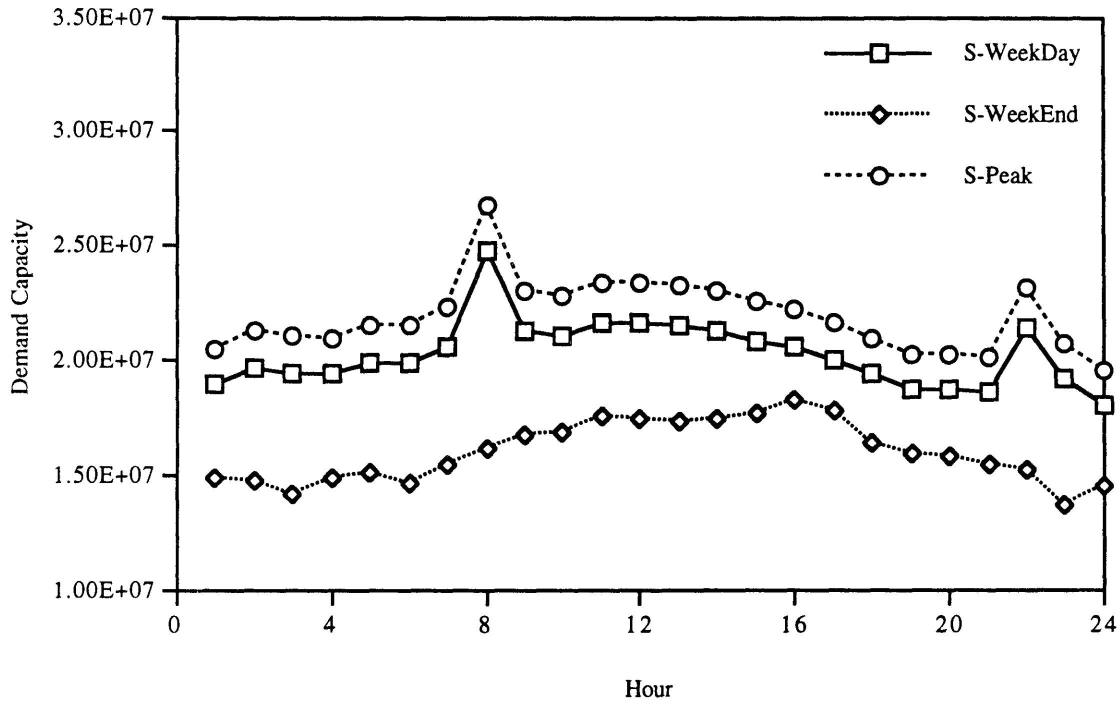


SIC 36-Electronic and Electric Equipment-Winter Load Shape

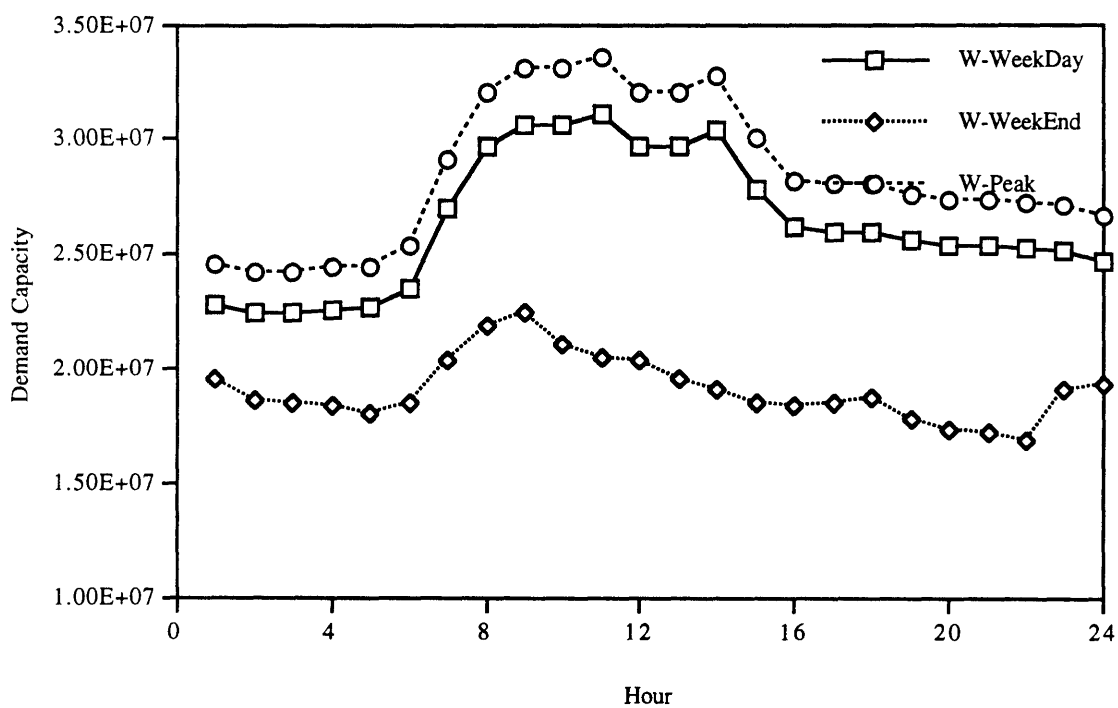


Transportation (SIC 37)

SIC 37-Transportation Equip-Summer Load Shape

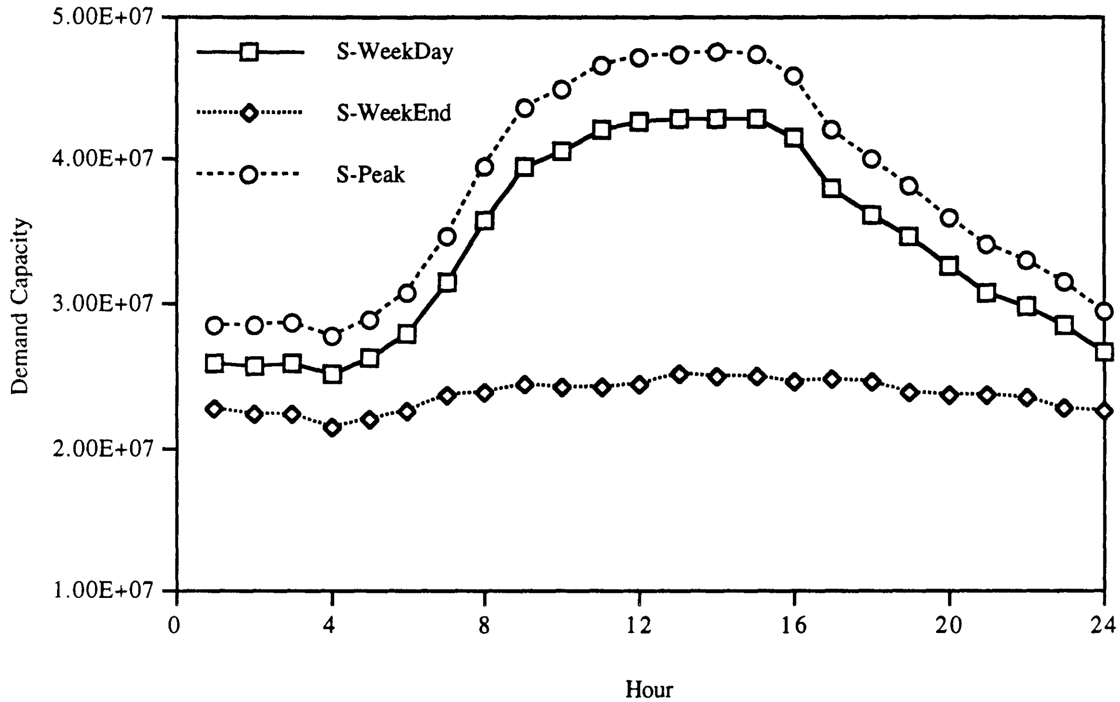


SIC 37-Transportation Equip-Winter Load Shape

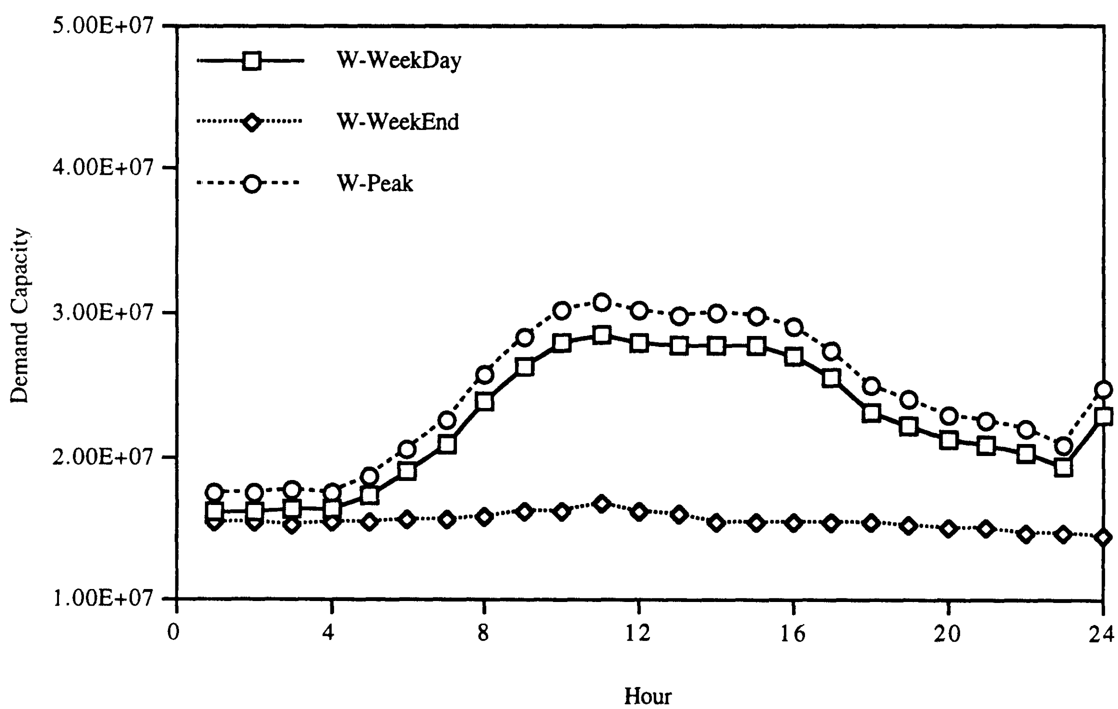


Instruments (SIC 38)

SIC 38-Instruments-Summer Load Shape

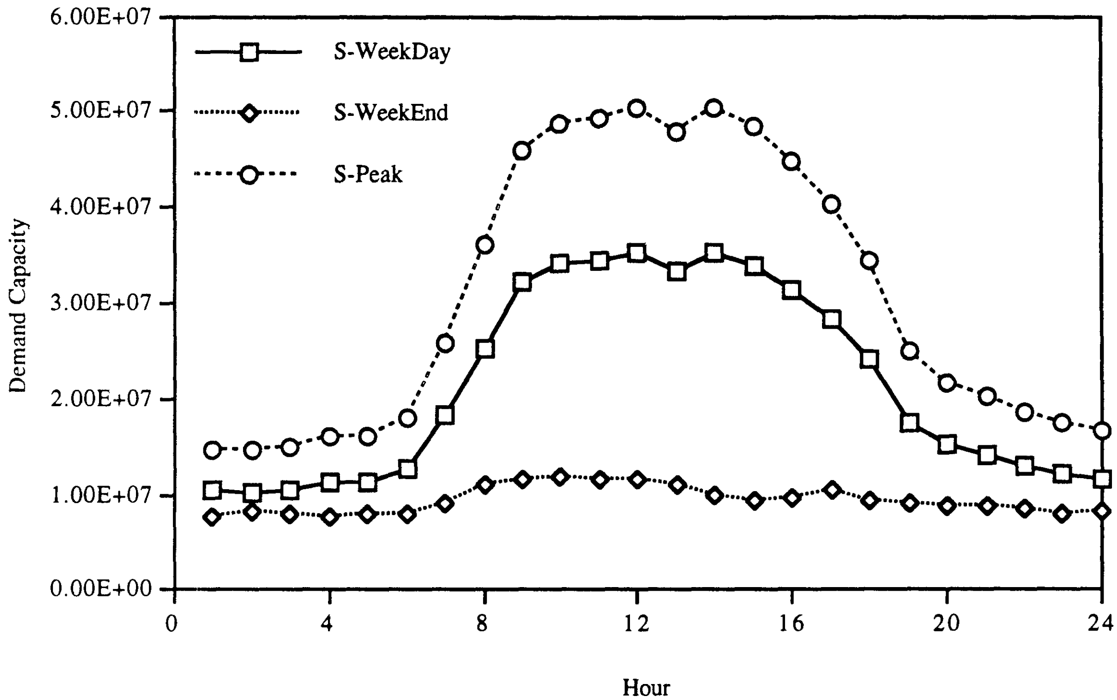


SIC 38-Instruments-Winter Load Shape

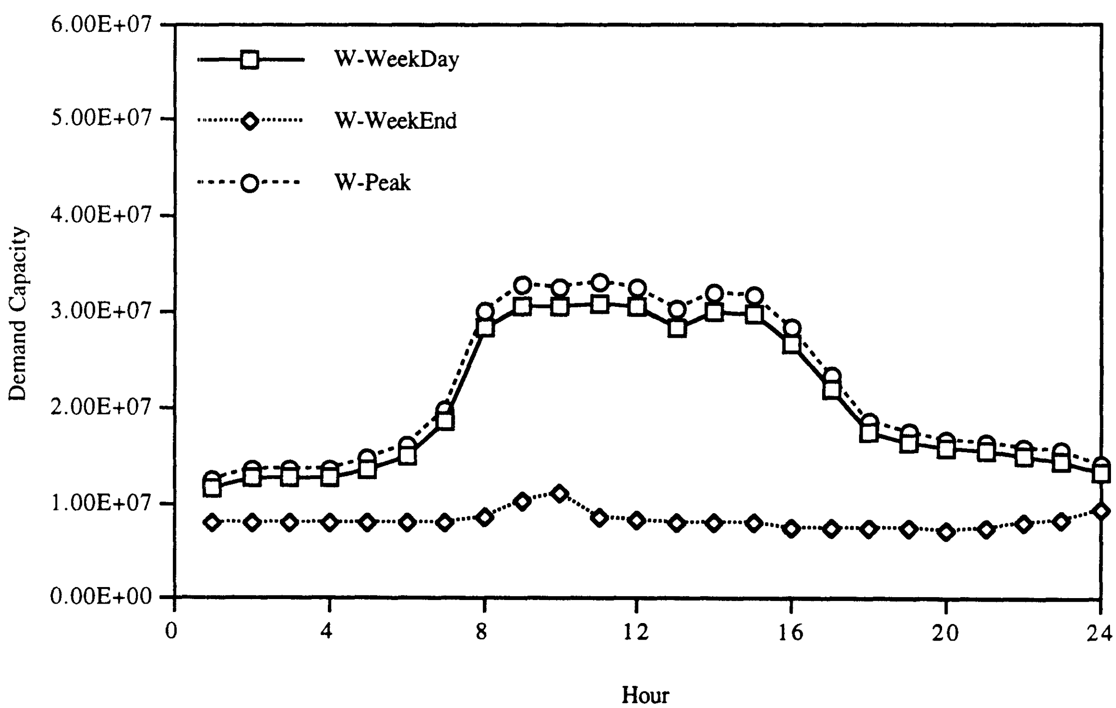


Misc Manufacturing (SIC 39)

SIC 39-Miscellaneous Manufacturing-Summer Load Shapes



SIC 39-Miscellaneous Manufacturing-Winter Load Shapes



Appendix B: Load Characteristics and the Load Factor

	Load Factor	Peak/ Average	Seasonal Demand	Weekend Consump	Peaking Amount	Peak Duration
Chemicals	69.19%		•		•	•
Electronic	68.60%	•	•			•
Paper	66.45%	•	•		•	
Transportation	64.83%	•		•	•	•
Grocery	64.28%			•	•	•
Hotel/Motel	62.72%			•	•	•
Office	62.27%		•			•
Industrial mach	61.48%	•			•	
Rubber	60.41%	•			•	
Primary Metal	57.60%	•	•			•
Food	56.77%	•			•	
Instruments	54.62%				•	
Retail	54.36%	•		•		•
Health	54.23%				•	
Restaurant	50.71%	•		•		•
S, C & G	49.95%	•				
Warehouse	49.21%	•	•			
Textile Mill	45.67%	•				
Printing	43.18%	•			•	
Education	39.29%					
Fab Metal	37.03%	•				
Miscellaneous	36.59%					
Misc. Manuf	34.96%					

This chart points out the various load shape characteristics that a consumer's consumption creates. The five classifications are the same ones that have been identified in Chapter 2. Each bullet establishes the presence of a good load characteristic. The high load factor customers have four or five of these characteristics, while the low load factor customers have one or none of these characteristics. Seasonal Demand eveness and low peakedness seem to be key drivers for determining load factor numbers.

Appendix C: Energy Consumption by Customer Group by Utility

BECO-Energy Needs by Customer Group

	Compilation-BECO	GigaWattHrs	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
	Office		3112	3166	3251	3360	3502	3630	3724	3786	3847	3903	3989
	Restaurant		300	295	297	295	295	297	296	294	296	295	296
	Retail		475	468	467	465	471	470	466	464	463	459	460
	Grocery		350	347	347	346	346	345	345	342	340	336	337
	Warehouse		302	296	295	291	290	288	285	283	281	278	280
	Education		893	897	906	917	923	933	946	945	953	959	968
	Health		786	779	794	792	794	794	797	808	812	812	824
	Hotel/Motel		292	300	313	323	335	347	362	372	380	387	396
	Miscellaneous		1049	1079	1111	1145	1181	1204	1218	1249	1260	1269	1303
	Total		7559	7627	7781	7934	8137	8308	8439	8543	8632	8698	8853

		GigaWattHrs	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
20	Food and Kindred Products		97	97	93	91	90	89	88	86	85	84	82
21	Tobacco Products		0	0	0	0	0	0		0	0	0	0
22	Textile Mill Products		17	17	17	18	18	18	19	19	19	20	21
23	Apparel and other Textile Products		23	24	24	24	24	25	25	25	26	26	26
24	Lumber and Wood Products		9	7	7	6	7	8	8	8	8	9	9
25	Furniture and Fixtures		6	6	6	6	6	6	6	6	7	7	7
26	Paper and Allied Products		122	125	122	126	130	133	134	134	134	135	136
27	Printing and Publishing		94	97	97	97	100	100	101	102	103	104	106
28	Chemicals and Allied Products		98	83	76	67	54	57	60	65	67	69	69
29	Petroleum and Coal Products		17	17	17	17	17	17	17	18	18	18	18
30	Rubber and Miscellaneous Plastics		66	69	69	71	73	76	78	80	83	86	88
31	Leather and leather products		1	0	0	0	0	0	0	0	0	0	0
32	Stone, clay and glass products		22	23	24	24	24	24	24	24	24	24	24
33	Primary Metal Industries		25	26	25	24	24	24	24	24	23	23	23
34	Fabricated Metal Products		82	82	79	77	78	81	84	88	91	93	94
35	Industrial machinery and equipment		279	279	272	269	269	263	254	243	233	223	216
36	Electronic and other electric equipmer		514	557	576	601	633	663	688	711	732	753	774
37	Transportation Equipment		43	45	45	46	46	51	52	54	56	58	59
38	Instruments and related Products		143	120	109	97	84	99	109	123	130	140	147
39	Micellaneous Manufacturing Industries		7	7	6	6	6	7	7	7	7	8	7
	Total		1665	1681	1664	1667	1683	1741	1778	1817	1846	1880	1906

NU-Energy Needs by Customer Group

	Compilation-NU	GigaWattHrs	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
	Office		3981	3959	4014	4087	4150	4213	4264	4308	4340	4376	0
	Restaurant		692	705	723	743	761	778	794	806	818	832	0
	Retail		1507	1529	1563	1598	1626	1649	1660	1664	1662	1662	0
	Grocery		928	946	971	998	1021	1044	1064	1083	1098	1116	0
	Warehouse		559	571	586	602	618	632	644	654	662	673	0
	Education		1084	1103	1146	1191	1171	1203	1224	1243	1259	1275	0
	Health		797	820	857	900	936	970	991	1009	1024	1042	0
	Hotel/Motel		399	410	430	451	470	488	502	514	526	536	0
	Miscellaneous		1728	1801	1901	1957	1990	2027	2071	2116	2162	2206	0
	Total		11675	11844	12191	12527	12743	13004	13214	13397	13551	13718	0

	Total NU	GigaWattHrs	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
20	Food and Kindred Products		327	329	330	332	334	335	337	338	340	341	343
21	Tobacco Products		0	0	0	0	0	0	0	0	0	0	0
22	Textile Mill Products		119	118	118	117	116	115	115	114	113	113	112
23	Apparel and other Textile Products		0	0	0	0	0	0	0	0	0	0	0
24	Lumber and Wood Products		0	0	0	0	0	0	0	0	0	0	0
25	Furniture and Fixtures		0	0	0	0	0	0	0	0	0	0	0
26	Paper and Allied Products		998	999	1,000	1,001	1,002	1,003	1,004	1,005	1,006	1,007	1,008
27	Printing and Publishing		201	207	213	219	226	232	239	246	253	261	269
28	Chemicals and Allied Products		371	380	390	399	409	419	430	440	451	463	474
29	Petroleum and Coal Products		0	0	0	0	0	0	0	0	0	0	0
30	Rubber and Miscellaneous Plastics		525	545	567	589	612	636	660	686	713	741	770
31	Leather and leather products		0	0	0	0	0	0	0	0	0	0	0
32	Stone, clay and glass products		174	175	176	177	178	179	179	180	181	182	183
33	Primary Metal Industries		446	445	445	444	443	442	442	441	440	439	439
34	Fabricated Metal Products		637	646	656	666	676	686	697	707	718	729	740
35	Industrial machinery and equipment		862	882	903	924	946	969	992	1,016	1,040	1,066	1,092
36	Electronic and other electric equipn		618	636	655	674	694	715	736	758	781	805	830
37	Transportation Equipment		619	636	653	671	689	707	726	746	766	786	808
38	Instruments and related Products		362	375	389	404	418	434	450	467	484	502	520
39	Micellaneous Manufacturing Industr		256	257	257	257	258	258	259	259	260	260	260
	Total		6,515	6,631	6,750	6,873	7,000	7,131	7,265	7,404	7,548	7,695	7,848

NEES-Energy Needs by Customer Group

	Compilation-NEES	GigaWattHrs	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
	Office		2,173	2,243	2,309	2,376	2,446	2,509	2,564	2,618	2,671	2,722	2,776
	Restaurant		585	605	625	646	666	687	708	729	751	772	794
	Retail		1,002	1,028	1,053	1,076	1,100	1,121	1,139	1,157	1,174	1,192	1,213
	Grocery		564	575	585	594	604	614	622	631	638	646	655
	Warehouse		552	566	581	593	606	620	635	647	662	675	689
	Education		909	931	943	965	987	1,003	1,017	1,033	1,039	1,048	1,058
	Health		861	904	946	986	1,031	1,073	1,105	1,137	1,163	1,192	1,219
	Hotel/Motel		274	283	293	304	315	324	335	344	358	365	377
	Miscellaneous		997	1,039	1,080	1,123	1,170	1,209	1,246	1,283	1,313	1,344	1,374
	Total		7,917	8,174	8,415	8,663	8,925	9,160	9,370	9,580	9,768	9,956	#####

	Summary-Numbers	GigaWattHrs	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
20	Food and Kindred Products		214	219	225	230	236	240	245	249	253	258	261
21	Tobacco Products		0	0	0	0	0	0	0	0	0	0	0
22	Textile Mill Products		183	184	185	187	188	189	189	190	190	191	190
23	Apparel and other Textile Products		0	0	0	0	0	0	0	0	0	0	0
24	Lumber and Wood Products		0	0	0	0	0	0	0	0	0	0	0
25	Furniture and Fixtures		0	0	0	0	0	0	0	0	0	0	0
26	Paper and Allied Products		300	307	313	320	327	333	339	345	351	357	363
27	Printing and Publishing		59	61	63	65	67	71	74	77	80	84	88
28	Chemicals and Allied Products		304	311	317	324	331	334	337	339	342	345	347
29	Petroleum and Coal Products		0	0	0	0	0	0	0	0	0	0	0
30	Rubber and Miscellaneous Plastics		687	717	748	778	808	844	881	917	953	989	1,030
31	Leather and leather products		0	0	0	0	0	0	0	0	0	0	0
32	Stone, clay and glass products		187	190	194	198	201	204	206	209	212	214	216
33	Primary Metal Industries		223	226	229	232	236	236	237	238	239	239	239
34	Fabricated Metal Products		250	253	256	258	261	267	274	280	286	292	298
35	Industrial machinery and equipment		564	582	599	617	635	665	695	725	756	786	805
36	Electronic and other electric equipment		780	774	768	762	757	792	828	863	899	934	992
37	Transportation Equipment		195	191	187	183	179	183	186	190	193	197	198
38	Instruments and related Products		222	227	232	237	242	246	251	255	260	264	268
39	Micellaneous Manufacturing Industries		152	155	157	160	162	166	169	172	175	179	181
	Nonclasified		486	483	481	478	476	492	508	524	540	556	569
	Total		4,805	4,880	4,956	5,031	5,106	5,262	5,418	5,573	5,729	5,885	6,045

Appendix D: Variables for Financial Model

Customer Features
Average Heat Rate
Load Factor
Capacity Plant Size

Financing Features
Equity Financing Percentage
Debt Financing Percentage
Cost of Equity
Cost of Debt
Debt Type
Debt Period

Taxes
Federal Corporate
State
Property/Local

Building Numbers
Plant Construction Cost
Land Cost
Land Requirements
Breaker Configuration
Number of Breakers
Number of Units

Fuel and Operations & Maintenance Numbers
1994-Variable Fuel Prices
1994-Fixed Fuel Prices (Pipeline charges)
1994-Variable O & M
1994-Fixed O & M
Yearly Escalation-Variable Fuel Prices
Yearly Escalation-Fixed Fuel Prices (Pipeline charges)
Yearly Escalation-Variable O & M
Yearly Escalation-Fixed O & M

Operational Numbers
Capacity Transmission Loss Compensation
Capacity Outage Loss Compensation
Maintenance Outage
Unforced Outage

Miscellaneous
Overhead costs based on Sales

Appendix E: Detailed Explanation of Financial Model Variables

Full Explanation of the Variables

To arrive at a consistent set of numbers to categorize unit (GTF) operation, a unified source of data was sought. NEPOOL's Generation Task Force publishes a yearly summary of long range study assumptions that is used for planning purposes and primarily address utility generation options.[16] The data is provided for purposes of evaluating generating units on a generic (with no unique requirements) basis. Actual costs and performance of specific generating units will vary due to site and plant specific conditions, and economic uncertainties. In this report, DRI/McGraw-Hill and the WEFA Group were contracted for some forecast values. Future unit data was based on a 1993 Stone and Webster study[17] and a 1993 EPRI study.[18]

Financing Features

To estimate the financing costs of this Generic New Entrant project, there are various factors to consider. Present financial schemes for utilities and non utility generators reflect the very risk free nature of the regulated utility enterprise. Traditional rates of return for utilities are low, based on the riskless nature of the revenue. Independent Power Producers and Non Utility Generators have guaranteed contracts with utilities and are safeguarded by the regulatory compact. Payment from utilities are one step from being risk-free, since the contract written by the utility is being backed by the regulatory compact. For this reason, financing of non utility generators can be highly leveraged. For most projects, the funding is usually derived from long term debt instruments, usually 15-20 year bonds. These bonds usually have a 9-11 percent coupon rate.[19] An IPP can leverage its financial structure up to 90 percent debt, with 80% being a

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[16]Summary of the Generation Task Force Long-Range Study Assumptions (GTF) (NEPOOL Generation Task Force Members, June 1994)

[17]Development of Engineering, Cost, and Performance Data for Generation Supply Options for New England, Final Report. (Stone & Webster Engineering Corporation, February 1993)

[18]Technical Assessment Guide, Volume I:Electric Study--1993 (Revision7) (Palo Alto:Electric Power Research Institute, June 1993)

[19]1993 Sithe Energy Annual Report: 13-15.

standard number.[20] IPPs could piece together these financing packages because of the almost guaranteed nature of payment by NUG customers, mainly utilities.

In a future competitive market, established utilities and new supplies will not be able to enjoy such riskless revenue flows. There will be a large measure of risk attached to the securing of customers and the flow of revenues. These large debt/equity financing ratios will have to adjust to reflect the riskier nature of the competitive marker. Projects will have to have more equity, rates of return will have to increase, and debt buyers will demand la better return. For the purposes of this model, the base case for this new supplier financing will be 20% equity and 80% debt. The debt will have a 17 year life expectancy and an 11% coupon yield. Equity will be expected to be paid back at a 20% rate. Although uncertainty will probably drive this ratio towards higher equity, there is little indication of where this ratio will settle upon. Current ratios are adopted for lack of a better indication.

Taxes

It is assumed that the plant project pays taxes on the income after deductions are allocated. It is assumed that there is a Federal Corporate Income Tax of 34% and a state income tax of 8% derived from a New England Weighted Average State Corporate Income Tax. It is also assumed that there will be a 2% local and property tax.[21]

Depreciation

It is assumed that the project will depreciate the plant on a declining balance account with a tax and physical life of 25 years and no salvage value.

Building Numbers

Overnight core plant costs are defined as the cost to build a plant as if all the expenditures were spent at one point of time. These costs are derived from the Stone and Webster Study and the NEPOOL Power Supply Planning Advisory Group (PSPAG) recommendations. The costs include all cost associated with the unit itself, including the generation step-up transformer, but do not include permitting, state and local taxes, switchyard, interconnection and land costs.[22] Because of the generic plant characteristics

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[20] 1993 AES Annual Report: 18-19.
[21] GTF. Exhibit 16: 37.
[22] GTF: 8.

no potential site specific costs are assumed. Potential site specific conditions that can alter the core overnight plant costs include:

Table 10. Overnight Construction Costs for Different Technology Types

Technology Type	1995-Overnight Costs $/kW
Combined Cycle	660.59
Combustion Turbine	513.79
Advanced Combined Cycle	660.59
Advanced Combustion Turbine	555.73

Fuel and Operations & Maintenance Numbers

In this study it is assumed that the Combined Cycle units burn natural gas and that the Peaking Combustion Turbines also burn natural gas. 365 Day Firm gas is assumed to be used for the CC units. Interruptible gas is assumed to be used for peaking Combustion Turbine units.

The cost of firm gas is assumed to have fixed and variable components. The fixed component of the fixed gas is assumed to escalate up to the first year of the fuel delivery and then remain constant over the life of the contract. It is assumed that contract are signed in ten years intervals, starting in 1995 and signed again in 2005 and 2015. Thus, the fixed component of natural gas costs behaves like a step function. The cost of interruptible gas is assumed to only have a variable component and represents the spot market average.

Fuel prices were developed by NEPLAN based on NEPOOL's historical replacement fuel costs (without fuel adders) and WEFA's Fall 1993 energy forecast. The price for existing interruptible gas (i.e. gas currently being burned during non-winter months on an as available and economic basis) was based on WEFA's Fall 1993 forecast. It is assumed that interruptible gas is available for the summer and winter months.[23] Gas delivery under firm transportation arrangements was assumed to have several components which can be grouped into variable and fixed price components of a firm gas price. The variable component presented in the GTF report and used here reflects gas supplies obtained from the Gulf of Mexico region and from Canada, as well as Canadian transportation costs and variable transportation costs charged by American pipeline companies. The fixed component of the firm gas price represents the fixed transportation

[23]GTF: 9.

costs charged by pipeline companies. Neither the fixed nor the variable component include charges by local distribution companies, and none is assumed.[24]

Operational Numbers

In this financial model, maintenance and unscheduled outages are modeled as regular occurrences. All power plants have regular maintenance down times to keep the plant running, and they also have unforeseen maintenance caused by breaks, leaks, explosions. meltdowns and such. This maintenance will bring the unit down completely or it will prevent the unit from reaching full capacity. These occurrences can be modeled as probability unit factors:

- Scheduled Outage(SOF)-Percent of time that plant is out for preventive maintenance
- Equivalent Forced Outage(EFOR)-Percent of time plant is out for auxiliary maintenance

Because these factors are calculated as independent occurrences the effective Equivalent Availability Factor(EAF) is calculated as follows:

EAF=(1-EFOR)-(1-EFOR)*SOF

When sizing up the needs for prospective customers, it was assumed in previous analysis that the capacity needs for the customer equated to the capacity needs for the supplier. Because a supplier will have planned and unplanned outages and there will be a cost associated with this, there needs to be some kind of accounting for this event. It is assumed that there will be a capacity penalty for outages based on the inverse of the equivalent Availability Factor. This factor increases the amount of capacity that the supplier has to maintain in order to maintain an uninterrupted supply of electricity to customers. Although much of the planned and unplanned maintenance brings a unit down fully, this capacity penalty models a straight derating of the unit. Although it is debatable that a capacity penalty will be an accurate representation of costs for replacement power for scheduled and unscheduled outages, it is a consistent approach that is applied to all cases and customers.

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[24]GTF: 9.

Table 11. Planned and Unplanned Equivalent Factors

	Scheduled Outage Factor	Equivalent Forced Outage Rate	Equivalent Avail Factor	Capacity Penalty
CC	0.0577	0.0449	0.9	1.1
CT	0.0192	0.0824	0.9	1.1
Advanced CC	0.0577	0.0449	0.9	1.1
Advanced CT	0.0192	0.0824	0.9	1.1

A second capacity factor penalty that is calculated involves transmission loses. Customer requirements have been measured at the customer side of the busbar. These electricity requirements do not translate to the plant requirements, who have to compensate for transmission losses in order to meet all the necessary load for the customer. These capacity and energy loses are not constant and the loses on the first kilowatt of demand are substantially lower than the loses on the last kilowatt of demand. As the transmission and distribution circuits become more heavily loaded and current on the lines and through transformers increases, loses on the system increase.[25] Average on peak loses for energy for a summer in a summer constrained system(NEES) is about 9% . Average on peak loses for energy for a winter in a summer constrained system is about 5.5%.[26] Since this study is generic in nature, no assumptions on transmission constraints will be used and a 5.5% energy loss factor will be utilized. The capacity needed to supply customers is increased by that transmission loss factor to ensure that enough energy is provided at the consumer end.

Misc.

There is an 8% overhead cost charge on gross revenues to reflect on going company overhead costs.

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[25]New England Electric System. Integrated Least Cost Resource Plan for the Fifteen Year Period 1994-2008 Volume III: The Resource Need Evaluation. Section 4.11 44.
[26]NEES-IRP:Vol III.Section 4.13 46.

Appendix F: Sample Financial Calculation Spreadsheet

Base Input		40	MW									
Outage Compensation		44.44	MW									
Transmission Loss Compensation		47.03	MW									
Unit Type	Combined Cycle											
Overnight Core Plant Cost		$660.59	$/kW									
Land Cost		177500	$/Acre									
Land Requirements		20	Acres									
BreakerConfiguration		3										
Number of Breakers		3										
NUmber of Units		1										
Transmission Loss Percentage		5.50%										
Base Plant		410										
Overhead		7%										
Tax Property/Local		2%										
Tax State		8%										
Tax Federal		34%										
Average Bond Maturity		17.00	Years									
Tax Life Time		25.00	Years									
Funding Model												
Common Stock		20.00%		11.50%	2.30%	$7.72						
Debt		80.00%		11.00%	8.80%	$30.90						
Preferred Stock		0.00%		8.00%	0.00%	$0.00						
			WCC		11.10%							
Cash Flow Costs Yearly		1		2	3	4	5					
		1.2		1.2	5	40.2	52.4					
Breaker Cost		$0.71	Million									
Plant Cost		$31.07	Million									
Land Cost		$0.41	Million									
Subtotal		$32.19	Million									
Fudge		1.2										
Total Contruction Costs		$38.62	Million									
Operating Features												
Ful Load Heat Rate	NPHR			8249.5555 Btu/kWhr								
Sceduled Outage Factor	SOF			4%								
Equivalent Forced Outage	EFOR			6%								
Equivalent Availability	EAF			90%								
Dispatch Percentage	DP			0.35								
Hours on Dispatch				2,759.37								
Electricity Produced	kWHrs			1.29778E+08								
Net Electricity Received	kWHrs			1.22640E+08								
Heat Produced	BTU			1.07E+12								
Year		*1995*		*1996*	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*
1994 Price (cents/kwhr)		8.608921706										
Escalation		4		4	4	4	4	4	4	4	4	4
Gas Price		8.609		8.953	9.311	9.684	10.071	10.474	10.893	11.329	11.782	12.253
Operations and Maintenance												
1993-Variable		0.10	$/MMBTU									
1993-Fixed		14.95	$/KWYR									
1994-Variable Gas		$0.14		3.7								
1994-Fixed Gas		$15.50		3.7								
Variable O&M		4.3		4.1	3.8	3.9	4	4	4.2	4.2	4.2	4.2
Fixed O&M		4.3		4.1	3.8	3.9	4	4	4.2	4.2	4.2	4.2
Variable O&M		$0.14		$0.15	$0.15	$0.16	$0.17	$0.17	$0.18	$0.19	$0.20	$0.20

Fixed O &M	$16.17	$16.83	$17.47	$18.15	$18.88	$19.64	$20.46	$21.32	$22.21	$23.15
Gas Prices										
1993-Variable Gas	2.04 $/MMBTU									
1993-Fixed Gas	0.88 $/MMBTU									
1994-Variable Gas	$2.06	1.9								
1994-Fixed Gas	$0.87	-1								
Variable Escalation-Gas	5.8	8.5	9.2	8.8	8.7	7.9	7.2	7.2	7.2	7.2
Fixed Escalation-Gas	2	1.1	1.3	1.7	1.9	1.8	2.1	2.1	2.1	2.1
	$64.87	$65.58	$66.43	$67.56	$68.85	$70.08	$71.56	$73.06	$74.59	$76.16
Variable Gas ($/MMBTU)	$2.16	$2.34	$2.56	$2.78	$3.02	$3.26	$3.50	$3.75	$4.02	$4.31
Fixed Gas ($/kw-yr)	$64.87	$64.87	$64.87	$64.87	$64.87	$64.87	$64.87	$64.87	$64.87	$64.87
Year	*1995*	*1996*	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*
Revenue	$11,172,467.28	$11,619,365.97	$12,084,140.61	$12,567,506.24	$13,070,206.49	$13,593,014.74	$14,136,735.33	$14,702,204.75	$15,290,292.94	$15,901,904.66
Variable Gas	$2,310,716.77	$2,507,127.70	$2,737,783.45	$2,978,708.39	$3,237,856.02	$3,493,646.65	$3,745,189.21	$4,014,842.83	$4,303,911.51	$4,613,793.14
Fixed Gas	$3,050,757.20	$3,050,757.20	$3,050,757.20	$3,050,757.20	$3,050,757.20	$3,050,757.20	$3,050,757.20	$3,050,757.20	$3,050,757.20	$3,050,757.20
Variable O &M	$152,980.39	$159,252.58	$165,304.18	$171,751.05	$178,621.09	$185,765.93	$193,568.10	$201,697.96	$210,169.27	$218,996.38
Fixed O&M	$760,491.57	$791,671.72	$821,755.25	$853,803.70	$887,955.85	$923,474.09	$962,260.00	$1,002,674.92	$1,044,787.26	$1,088,668.33
Total Gas Cost	$0.0484	$0.0502	$0.0522	$0.0544	$0.0567	$0.0590	$0.0613	$0.0637	$0.0663	$0.0691
Bond Interest	$2.72	$2.72	$2.72	$2.72	$2.72	$2.72	$2.72	$2.72	$2.72	$2.72
Capitalized Bond	$0.69	$0.69	$0.69	$0.69	$0.69	$0.69	$0.69	$0.69	$0.69	$0.69
Depreciation Balance	$38.62	$35.53	$32.69	$30.08	$27.67	$25.46	$23.42	$21.55	$19.82	$18.24
Declining Balance	$3.09	$2.84	$2.62	$2.41	$2.21	$2.04	$1.87	$1.72	$1.59	$1.46
Sales	$11,172,467.28	$11,619,365.97	$12,084,140.61	$12,567,506.24	$13,070,206.49	$13,593,014.74	$14,136,735.33	$14,702,204.75	$15,290,292.94	$15,901,904.66
Cost of Goods	$6,274,945.94	$6,508,809.21	$6,775,600.08	$7,055,020.35	$7,355,190.17	$7,653,643.87	$7,951,774.51	$8,269,972.91	$8,609,625.26	$8,972,215.06
Overhead	$782,072.71	$813,355.62	$845,889.84	$879,725.44	$914,914.45	$951,511.03	$989,571.47	$1,029,154.33	$1,070,320.51	$1,113,133.33
Depreciation	$3,089,945.59	$2,842,749.94	$2,615,329.94	$2,406,103.55	$2,213,615.26	$2,036,526.04	$1,873,603.96	$1,723,715.64	$1,585,818.39	$1,458,952.92
Bond Issue-Interest	$2,719,152.12	$2,719,152.12	$2,719,152.12	$2,719,152.12	$2,719,152.12	$2,719,152.12	$2,719,152.12	$2,719,152.12	$2,719,152.12	$2,719,152.12
Income Before Taxes	($1,693,649.07)	($1,264,700.91)	($871,831.37)	($492,495.21)	($132,665.51)	$232,181.68	$602,633.28	$960,209.75	$1,305,376.67	$1,638,451.23
Federal Taxes	($575,840.68)	($429,998.31)	($296,422.67)	($167,448.37)	($45,106.27)	$78,941.77	$204,895.31	$326,471.31	$443,828.07	$557,073.42
State Taxes	($135,491.93)	($101,176.07)	($69,746.51)	($39,399.62)	($10,613.24)	$18,574.53	$48,210.66	$76,816.78	$104,430.13	$131,076.10
Property Taxes	($33,872.98)	($25,294.02)	($17,436.63)	($9,849.90)	($2,653.31)	$4,643.63	$12,052.67	$19,204.19	$26,107.53	$32,769.02
Income	($1,693,649.07)	($1,264,700.91)	($871,831.37)	($492,495.21)	($132,665.51)	$130,021.74	$337,474.64	$537,717.46	$731,010.93	$917,532.69
Cash Flow Analysis										
Cash-Depreciation	$3,089,945.59	$2,842,749.94	$2,615,329.94	$2,406,103.55	$2,213,615.26	$2,036,526.04	$1,873,603.96	$1,723,715.64	$1,585,818.39	$1,458,952.92
Retirement of Debt	$694,356.64	$694,356.64	$694,356.64	$694,356.64	$694,356.64	$694,356.64	$694,356.64	$694,356.64	$694,356.64	$694,356.64
Cash Equivalent	$2,395,588.94	$2,148,393.30	$1,920,973.30	$1,711,746.90	$1,519,258.62	$1,342,169.40	$1,179,247.32	$1,029,359.00	$891,461.75	$764,596.28
Cash Basis Return	$701,939.88	$883,692.38	$1,049,141.93	$1,219,251.69	$1,386,593.11	$1,472,191.14	$1,516,721.95	$1,567,076.46	$1,622,472.68	$1,682,128.97
Equity Investment	$7,724,863.96									
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Cash Flow to Company	$701,939.88	$883,692.38	$1,049,141.93	$1,219,251.69	$1,386,593.11	$1,472,191.14	$1,516,721.95	$1,567,076.46	$1,622,472.68	$1,682,128.97
Net Flows	($7,022,924.09)	$883,692.38	$1,049,141.93	$1,219,251.69	$1,386,593.11	$1,472,191.14	$1,516,721.95	$1,567,076.46	$1,622,472.68	$1,682,128.97
IRR	20.0000%									
		20%								
NPV Calc	-7022924.088	736410.3194	728570.7815	705585.4715	668688.8053	591640.6021	507947.1127	437342.2789	377335.2907	326007.8633
Total	0.00									

Appendix G: Price Paths for O&M Costs

Table 12. Operations and Maintenance Costs for CC and GT Plants

	O & M Variable $/MBTU	CC Fixed $/kW-YR	O & M Variable $/MBTU	CT Fixed $/kW-Yr	O & M Variable Escalator	O &M Fixed Escalator
1993		14.95		0.15		
1994	0.14	15.50	0.34	0.16	3.7	3.7
1995	0.14	16.17	0.35	0.16	4.3	4.3
1996	0.15	16.83	0.37	0.17	4.1	4.1
1997	0.15	17.47	0.38	0.18	3.8	3.8
1998	0.16	18.15	0.39	0.18	3.9	3.9
1999	0.17	18.88	0.41	0.19	4.0	4.0
2000	0.17	19.64	0.43	0.20	4.0	4.0
2001	0.18	20.46	0.44	0.21	4.2	4.2
2002	0.19	21.32	0.46	0.21	4.2	4.2
2003	0.20	22.21	0.48	0.22	4.2	4.2
2004	0.20	23.15	0.50	0.23	4.2	4.2
2005	0.21	24.12	0.52	0.24	4.2	4.2
2006	0.22	25.13	0.55	0.25	4.2	4.2
2007	0.23	26.19	0.57	0.26	4.2	4.2
2008	0.24	27.29	0.59	0.27	4.2	4.2
2009	0.25	28.43	0.62	0.29	4.2	4.2
2010	0.26	29.63	0.64	0.30	4.2	4.2
2011	0.27	30.87	0.67	0.31	4.2	4.2
2012	0.28	32.17	0.70	0.32	4.2	4.2
2013	0.30	33.52	0.73	0.34	4.2	4.2
2014	0.31	34.93	0.76	0.35	4.2	4.2
2015	0.32	36.40	0.79	0.37	4.2	4.2
2016	0.34	37.92	0.82	0.38	4.2	4.2
2017	0.35	39.52	0.86	0.40	4.2	4.2
2018	0.36	41.18	0.90	0.41	4.2	4.2
2019	0.38	42.91	0.93	0.43	4.2	4.2
2020	0.40	44.71	0.97	0.45	4.2	4.2

Appendix H: Cost Paths for Gas Prices

Table 13. 1993-2020 Variable and Fixed Gas Fuel Prices

	Fuel Variable $/MMBTU	Delta %	Fuel Fixed $/kW-Yr	Delta %
1993	2.04		64.24	
1994	2.06	1.9	63.59	(1.0)
1995	2.16	5.8	64.87	2.0
1996	2.34	8.5	65.58	1.1
1997	2.56	9.2	66.43	1.3
1998	2.78	8.8	67.56	1.7
1999	3.02	8.7	68.85	1.9
2000	3.26	7.9	70.08	1.8
2001	3.50	7.2	71.56	2.1
2002	3.75	7.2	73.06	2.1
2003	4.02	7.2	74.59	2.1
2004	4.31	7.2	76.16	2:1
2005	4.62	7.2	77.76	2.1
2006	4.92	6.6	79.94	2.8
2007	5.25	6.6	82.17	2.8
2008	5.60	6.6	84.48	2.8
2009	5.97	6.6	86.84	2.8
2010	6.36	6.6	89.27	2.8
2011	6.78	6.6	91.77	2.8
2012	7.23	6.6	94.34	2.8
2013	7.70	6.6	96.98	2.8
2014	8.21	6.6	99.70	2.8
2015	8.75	6.6	102.49	2.8
2016	9.33	6.6	105.36	2.8
2017	9.95	6.6	108.31	2.8
2018	10.60	6.6	111.34	2.8
2019	11.30	6.6	114.46	2.8
2020	12.05	6.6	117.66	2.8

Appendix I: Qualitative Features of Customers

What at one point was unimportant data describing customers and their usage of electricity will become all to valuable as different firms compete for the right to serve them. In the previous section we have examined various quantitative indexes using load shape profiles of these typical/average customers. However, it is also important to examine other customer characteristics that might reveal whether there is reason to turn a reasonable profit serving any given customer. For example, individual customers might be subject to output growth trends compared to other customers which might have stagnating or declining output. The computer industry is seemingly always in an expansionary booming cycle, but the defense industry is suffering from the end of the cold war and face a shrinking future.

Much of the information collected by utilities for planning and DSM conservation measures will take added dimensions as this information could be used to identify profitable and unprofitable market segments. Integrated Resource Plans for the various electric utilities give us the beginning of these information needs as they identify the overall trends for customers. For the New England area, a variety of information can be obtained to survey these potential deregulated customers. Growth patterns and end use market break down information could be used to identify these customers and give a hint on how a competitive market will serve consumer needs. A sample of this type of information can be seen in the 1994 BECO IRP,[27] which describes the prospects of load growth in their service area for the next ten years:

- Office buildings continue to dominate the commercial market in absolute electricity sales volume
- Hotels and Public offices will be the fastest growing markets
- Educational facilities growth will be constrained by demographics
- Other building groups relying on population growth will be stagnant in energy usage: Groceries, Retail. Restaurant, and Warehouse

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[27]Boston Edison Company Integrated Resource Management Initial Filing. Book 1. (15 July 1994) A.3-7

- Until the end of 1994 and probably in the future, hospitals and other health facilities will face a unique uncertainty regarding the scope and the schedule of national health reform

- Key drivers of growth will be air conditioning, ventilation and miscellaneous end uses of electricity

- Miscellaneous end use growth will be driven by increased electrification of the commercial workplace, e.g. personal computers, fax machines and control systems

- The largest end use market will continue to be lighting, but its sales volume will be essentially flat.

- Growth in floor space served by some end uses is offset by the efficiency increase in replacement equipment

Commercial

Office/Public (Office)

Office buildings will continue to be the largest commercial group in terms of employment and floor space. High vacancy rates that have plagued these buildings will return to normal by 2003. Improvements in lighting efficiencies will hold lighting load constant

Restaurant (Restaurant)

Restaurant will remain among the smallest individual building groups in total electricity usage. There will be a decline in the share of the heating market. There will be significant improvements in lighting and water heating replacements. Miscellaneous growth will be at a slower rate than most other building markets

Retail (Retail)

Retail group will continue to experience high vacancy rates. There is very little employment growth expected. Efficiency gains in lighting replacements will contribute to a net reduction in electricity consumed. There is little additional electricity-using equipment expected to be installed for these customers.

Grocery (Grocery)

Slow population growth and flat grocery employment create no growth in total floor space. There will be no growth in air conditioning load and efficiency gains in lighting retrofitting will lead to less overall electricity usage. There will be no increase in electrical refrigeration market.

Warehouse (Warehouse)

There will be a net shrinkage in total energy due to slow growth in population and wholesale trade jobs, in combination with significant lighting efficiency increases. High vacancy rates will slowly return to normal. The automation of inventory control systems will spur strong miscellaneous use growth

Elem./Secondary/College/University (Education)

Massachusetts Educational Reform Funds will expand employment and facilities. Growth will be led by air conditioning and miscellaneous end uses of electricity. Miscellaneous end use growth will be driven by greater computer use is schools. For colleges there will be moderate growth in employment and physical plant. However, lighting and water heating efficiencies are expected from the replacement of existing systems. Increased computer usage in classrooms, dormitories and administrative offices will cause miscellaneous end use growth.

Hospital/Other Health (Health)

Hospitals are expected to show moderate growth in employment and facilities. Water heating decreases slightly due to rising prices. Miscellaneous end use of electricity increases due to the adoption of new medical equipment. The impact of Health Care Reform is a unique uncertainty that is hard to quantify.

Hotel/Motel (Hotel/Motel)

Hotels are expected to be the fastest growing building group. A larger stock of floor space leads to a significant growth in air conditioning and miscellaneous energy sales. Very strong miscellaneous end use growth driven by greater electrification of hotel rooms, e.g. computers, printers, fax machines, etc. There will be a decline in the electricity share of the heating market.

Misc. (Com-Misc.)

Miscellaneous buildings group will grow at twice the rate of the commercial sector in terms of employees and space. Most of the growth will be driven by the need for auxiliary business services. There will be significant electrical energy gains in the HVAC market. New space will lead to a net increase in lighting energy sales.

Manufacturing[28]

SIC 20-Food and Kindred Products (Food)

This group includes establishments manufacturing foods and beverages for human consumption and certain related products such as manufactured ice, chewing gum, vegetable and animal fat and oils, and prepared feeds for animals and fowls.

SIC 21-Tobacco Products (Tobacco)

This group includes establishments engaged in manufacturing cigarettes, cigars, smoking and chewing tobacco, snuff, and reconstituted tobacco and in stemming and redrying tobacco.

SIC 22-Textile Mill Products (Textile Mill)

Establishments in this group are engaged in 1) preparing fiber and manufacturing of yarn, thread, braids, twine and cordage 2) manufacturing broad, narrow and knit woven fabrics, and carpets and rugs from yarn 3) dyeing an d finishing fiber, yarn, fabrics, and knit apparel 4) coating, waterproofing, or otherwise treating fabrics 5) manufacturing knit apparel and other finished articles from yarn 6) the manufacture of felt goods, lace goods, nonwooven fabrics and miscellaneous textiles

SIC 23-Apparel and Other Textile Products (Apparel)

This group is know as the cutting-up and needle trades and they include establishments producing clothing and fabricating products by cutting and sewing purchased woven or knit fabrics and related materials, such as leather, rubberized fabrics, plastics, and furs.

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[28]Energy Information Agency. *Appendix D. Descriptions of Major Industrial Groups and Selected IndustrManufacturing* Energy Consumption Survey:Consumption of Energy 1988 (Washington, DC: Energy Information Agency, May 1988) 195.

SIC 24-Lumber and Wood Products (Lumber)
Establishments in these groups are engaged in cutting timber and pulpwood; merchant sawmills, lath mills, shingle mills, cooperage stock mills, planing(sic) mills, and plywood and veneer mills engaged in producing lumber and wood basic materials, and establishments engaged in manufacturing finished articles made entirely or mainly of wood or related products.

SIC 25-Furniture and Fixtures (Furniture)
These establishments manufacture household, office, public building and restaurant furniture and office and store fixtures

SIC 26-Paper and Allied Products (Paper)
This major group includes establishments primarily engaged in the manufacture of pulps from wood and other cellulose fibers, and from rags. The manufacture of paper and paper board, and the manufacture of paper and paperboard into converted products, such as paper coated paper machine, paper bags, establishments.

SIC 27-Printing and Publishing (Printing)
These establishments are engaged in printing by one or more common processes, such as letterpress, lithography,, gravure, or screenl and those establishments which perform services for the printing trade, such as bookbinding and plate making.

SIC 28-Chemicals and Allied Products (Chemicals)
Establishments in this group produce basic chemicals, and manufacture products by predominantly chemical processes. Three general classes of products are created by these establishments. 1) Basic chemicals, such as acids, alkalines, salts and organic chemicals; 2) chemical products to be used in further manufacture such as synthetic fibers, plastics materials, such as drugs, dry colors, 3) finished chemical products to be used for ultimate consumption, such as drugs, cosmetics, and soaps; or to be used as materials or supplies in other industries, such as paints. fertilizers, and explosives

SIC 29-Petroleum Refining and Related Industries (Petroleum)
This major group includes establishments primarily engaged in petroleum refining, manufacturing paving and roofing materials, and compounding lubricating oils and greases from purchased materials

SIC 30-Rubber and Miscellaneous Plastics Products (Rubber and Plastics)
Establishments from this group are engaged in manufacturing products, not elsewhere classified, from plastics, resins, and from natural, synthetics, or reclaimed rubber, gutta percha, balata, or gutta siak

SIC 31-Leather and Leather Products (Leather)
This group practices tanning, currying, and finishing of hides and skins, leather converters and produces finished leather and artificial leather products and some similar products made of other materials.

SIC 32-Stone, Clay, Glass and Concrete Products (Stone, Clay and Glass)
This major group includes establishments in the business of manufacturing flat glass and other glass products, cement, structural clay products, pottery, concrete, and gypsum products, cut stone, abrasive and asbestos products, and other products from materials taken primarily from the earth in the form of stone, clay, and sand

SIC 33-Primary Metal Industries (Primary Metals)

These establishments practice business in smelting and refining ferrous and nonferrous metals from ore, pig, or scrap; in rolling, drawing, and alloying metals; in manufacturing castings and other basic metal products; and in manufacturing nails, spikes, and insulated wire and cable.

SIC 34-Fabricated Metal Products (Fabricated Metals)

These establishments engage in fabricating ferrous and non ferrous metal products such as metal cans, tinware, handtools, cutlery, general hardware, nonelectric heating apparatus, fabricated structural metal products, metal forgings, metal stampings, ordnance, and a variety of metal and wire products, not elsewhere classified

SIC 35-Industrial Machinery and Equipment (Industrial Mach)

Establishments in this group engage in manufacturing industrial and commercial machinery and equipment and computers

SIC 36-Electronic and Other Electric Equipment (Electronic)

This group includes establishments engaged in manufacturing machinery, apparatus, and supplies for the generation, storage, transmission, transformation, and utilization of electrical energy.

SIC 37-Transportation Equipment (Transportation)

This major group includes establishments engaged in manufacturing equipment for transportation of passengers and cargo by land, air and water.

SIC 38-Instruments and Related Products (Instruments)

Companies in this categories engage in manufacturing instruments (including professional and scientific) for measuring, testing, analyzing, and controlling, and their associated sensors and accessories; meteorological, and geophysical equipment; search, detection, navigation, and guidance systems and equipment; surgical, medical. and dental instruments. equipment and supplies; ophthalmic goods; photographic equipment and supplies; and watches and clocks.

SIC 39-Miscellaneous Manufacturing Industries (Misc. Manuf)

Appendix J: Aggregation EXCEL Solver Output

Microsoft Excel 4.0 Answer Report
Worksheet: Maximize Factoring-Total
Report Created: 2/26/95 19:08

Target Cell (Max)

Cell	Name	Original Value	Final Value
B120	IRR BTU	13.9390%	34.5210%

Adjustable Cells

Cell	Name	Original Value	Final Value
D143	Offices Btu/kWhr	0	0
D144	Restaurants Btu/kWhr	0	0
D145	Groceries Btu/kWhr	0	0.223368134
D146	Education Btu/kWhr	0	0
D147	Retail Btu/kWhr	0	0
D148	Health Btu/kWhr	0	0
D149	Hotel Btu/kWhr	0	1
D150	Misc Btu/kWhr	0	0
D151	Warehouse Btu/kWhr	0	0
D152	Food and Kindred Products Btu/kWhr	0	0
D153	Textile Mill Products Btu/kWhr	0	0
D154	Paper and Allied Products Btu/kWhr	0	0
D155	Printing and Publishing Btu/kWhr	0	0
D156	Chemicals and Allied Products Btu/kWhr	0.5	1
D157	Rubber and Miscellaneous Plastics Btu/kWhr	0	0
D158	Stone, clay and glass products Btu/kWhr	0	0
D159	Primary Metal Industries Btu/kWhr	0	0
D160	Fabricated Metal Products Btu/kWhr	0	0
D161	Industrial machinery and equipment Btu/kWhr	0	0
D162	Electronic and other electric equipment Btu/kWhr	0	0
D163	Transportation Equipment Btu/kWhr	0	0
D164	Instruments and related Products Btu/kWhr	0	0
D165	Micellaneous Manufacturing Industries Btu/kWhr	0	0

Constraints

Cell	Name	Cell Value	Formula	Status	Slack
D143	Offices Btu/kWhr	0	D143<=1	Not Binding	1
D144	Restaurants Btu/kWhr	0	D144<=1	Not Binding	1
D145	Groceries Btu/kWhr	0.223368134	D145<=1	Not Binding	0.776631866
D146	Education Btu/kWhr	0	D146<=1	Not Binding	1
D147	Retail Btu/kWhr	0	D147<=1	Not Binding	1
D148	Health Btu/kWhr	0	D148<=1	Not Binding	1
D149	Hotel Btu/kWhr	1	D149<=1	Binding	0
D150	Misc Btu/kWhr	0	D150<=1	Not Binding	1
D151	Warehouse Btu/kWhr	0	D151<=1	Not Binding	1
D152	Food and Kindred Products Btu/kWhr	0	D152<=1	Not Binding	1
D153	Textile Mill Products Btu/kWhr	0	D153<=1	Not Binding	1
D154	Paper and Allied Products Btu/kWhr	0	D154<=1	Not Binding	1
D155	Printing and Publishing Btu/kWhr	0	D155<=1	Not Binding	1
D156	Chemicals and Allied Products Btu/kWhr	1	D156<=1	Binding	0
D157	Rubber and Miscellaneous Plastics Btu/kWhr	0	D157<=1	Not Binding	1
D158	Stone, clay and glass products Btu/kWhr	0	D158<=1	Not Binding	1
D159	Primary Metal Industries Btu/kWhr	0	D159<=1	Not Binding	1
D160	Fabricated Metal Products Btu/kWhr	0	D160<=1	Not Binding	1
D161	Industrial machinery and equipment Btu/kWhr	0	D161<=1	Not Binding	1
D162	Electronic and other electric equipment Btu/kWhr	0	D162<=1	Not Binding	1
D163	Transportation Equipment Btu/kWhr	0	D163<=1	Not Binding	1
D164	Instruments and related Products Btu/kWhr	0	D164<=1	Not Binding	1
D165	Micellaneous Manufacturing Industries Btu/kWhr	0	D165<=1	Not Binding	1
D143	Offices Btu/kWhr	0	D143>=0	Binding	0
D144	Restaurants Btu/kWhr	0	D144>=0	Binding	0
D145	Groceries Btu/kWhr	0.223368134	D145>=0	Not Binding	0.223368134
D146	Education Btu/kWhr	0	D146>=0	Binding	0
D147	Retail Btu/kWhr	0	D147>=0	Binding	0
D148	Health Btu/kWhr	0	D148>=0	Binding	0
D149	Hotel Btu/kWhr	1	D149>=0	Not Binding	1
D150	Misc Btu/kWhr	0	D150>=0	Binding	0
D151	Warehouse Btu/kWhr	0	D151>=0	Binding	0
D152	Food and Kindred Products Btu/kWhr	0	D152>=0	Binding	0
D153	Textile Mill Products Btu/kWhr	0	D153>=0	Binding	0
D154	Paper and Allied Products Btu/kWhr	0	D154>=0	Binding	0
D155	Printing and Publishing Btu/kWhr	0	D155>=0	Binding	0
D156	Chemicals and Allied Products Btu/kWhr	1	D156>=0	Not Binding	1
D157	Rubber and Miscellaneous Plastics Btu/kWhr	0	D157>=0	Binding	0
D158	Stone, clay and glass products Btu/kWhr	0	D158>=0	Binding	0
D159	Primary Metal Industries Btu/kWhr	0	D159>=0	Binding	0
D160	Fabricated Metal Products Btu/kWhr	0	D160>=0	Binding	0
D161	Industrial machinery and equipment Btu/kWhr	0	D161>=0	Binding	0
D162	Electronic and other electric equipment Btu/kWhr	0	D162>=0	Binding	0
D163	Transportation Equipment Btu/kWhr	0	D163>=0	Binding	0
D164	Instruments and related Products Btu/kWhr	0	D164>=0	Binding	0
D165	Micellaneous Manufacturing Industries Btu/kWhr	0	D165>=0	Binding	0