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Electrical Service Reliability: The Customer Perspective

by

M. E. Samsa, K. A. Hub, and G. C. Krohm

Argonne National Laboratory

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Energy and Environmental Systems Division

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Energy and Environmental Systems Division

September 1978

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FOREWORD

The Energy and Environmental Systems Division at Argonne National Laboratory is investigating the aspects of electric utility system reliability that could be affected by future energy policies or technologies. The work is being performed for the Office of Technical Programs Evaluation, Assistant Secretary for Policy and Evaluation, U.S. Department of Energy. The investigation is being made from two perspectives -- the customer's and the utility's. This report is concerned with the customer perspective of reliability and describes Argonne's efforts to date on that subject. As the report indicates, additional activities related to the customer view of electric utility reliability is continuing at Argonne. Additionally, study related to the utility perspective of reliability is progressing concurrently.

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ABSTRACT

Electric utility system reliability criteria have traditionally been established as a matter of utility policy or through long-term engineering practice, generally with no supportive customer cost-benefit analysis as justification. This report presents the results of initial study of the customer perspective toward electric utility system reliability, based on critical review of over 20 previous and ongoing efforts to quantify the customer's value of reliable electric service. A possible structure of customer classifications is suggested as a reasonable level of disaggregation for further investigation of customer value, and these groups are characterized in terms of their electricity use patterns. The values that customers assign to reliability are discussed in terms of internal and external cost components. A list of options for effecting changes in customer service reliability is set forth and some of the many policy issues that could alter customer service reliability are identified.

1 SUMMARY AND CONCLUSIONS

Traditionally, electric utility system reliability has been discussed in terms of the utility's generator and transmission line reliability criteria as used in system expansion planning. Although most utilities have some criteria to which system expansion is designed, there is generally no supportive customer cost-benefit analysis used to justify the reliability target levels which are usually established as a matter of utility policy or through long-term engineering practice.

Within the last decade several major electrical power outages have increased public awareness of the effects of widespread losses of service.

Customer groups, regulatory commissions, utilities and policymakers are questioning current reliability practices in an effort to determine the social costs of providing different levels of electric service reliability. Service reliability is defined as the level of continuity and quality of electrical supply to a utility customer's end-use device. In question is how the customer's needs for power and the utility's requirements to supply power might be satisfied most equitably as energy and capital become less available and as new technologies are introduced into the utility systems. These questions can be better addressed as researchers learn more about the value of electric service reliability to various customer groups and how this value relates to the expected frequency and duration of power interruptions, and to various economic and demographic characteristics.

As the major energy technology developer and policymaker, the U.S. Department of Energy (DOE) is studying the potential effects associated with alternative technological and policy options as they relate to electric service reliability. This report presents results from the initial activities of one of these studies, focusing on the customer perspective toward utility system reliability.

The objectives of this report are: (1) to present a brief review of the literature and of current efforts to quantify the customer's value of reliability, (2) to provide an initial structure for classifying customer groups that is appropriate for future analysis of utility reliability, (3) to set forth a list of options for altering service reliability, and (4) to identify some of the many related policy implications. This document is an initial and interim report of these efforts. Additional work related to the customer perspective, and the utility view as well, is continuing at Argonne.

1.1 VALUE OF RELIABILITY STUDIES

Major emphasis was placed on the review of previous and ongoing efforts to quantify the value to the customer of electrical service reliability. This review has found that nearly all of the previous studies that estimate this value have relied upon easily obtainable surrogate social cost indicators such as gross regional or national product, wages and salaries, or value added by manufacture. In general, these studies assume that an aggregate social value of reliable electricity is directly proportional to one of these indices for a specified geographic area divided by the electric kilowatt-hours consumed in the same area. This aggregate level of quantification is insufficient from a policy evaluation standpoint because of wide diversity in service areas and associated customer mixes, and because of wide variation in customer losses resulting from power interruptions. These indices are also inadequate because they provide only a crude indication of customer losses and are insensitive to variations in interruption frequency and duration that have been shown to be important factors to many customers.

Four works referenced most frequently in discussions about electric utility reliability are those of M.L. Telson (1972, 1975), R.B. Shipley, et al. (1972), and A. Kaufman (1975). The customer value of reliability as estimated in each of these reports is shown in Table 1.1.

Each of the four works estimates the value of electric service reliability in an effort to determine, or to demonstrate a methodology for determining, a socially optimum level of reliability. Telson and Kaufman adopt a probabilistic approach to determining a socially optimum level of utility generation reliability, while Shipley, et al., analyze only one year of actual data but consider both generation and transmission reliability. Based on comparisons of marginal customer costs and utility expenditures at

Table 1.1. Value of Reliability Estimates

Author	Methodology	Estimate
M.L. Telson (1972)	New York Power Pool (NYPP) Wages/ NYPP Industrial & Commercial kWh	$1.17/kWh
M.L. Telson (1975)	a. NYPP Wages/NYPP Industrial & Commercial kWh	$1.22/kWh
	b. U.S. Wages/U.S. Industrial & Commercial kWh	$ .57/kWh
R.B. Shipley, et al. (1972)	GNP/Total U.S. kWh	$ .60/kWh
A. Kaufman (1975)	Peaking generation owning & operating costs in $/kWh x $\frac{\text{NYPP Value Added}}{\text{NYPP Elec. Revenues}}$	$ .77/kWh

various levels of reliability, each author concludes that utility reliability exceeds its social optimum; their results range between 5 to 10 times the optimum level.*

Fifteen other U.S. and European studies have made estimates of the value of electric utility reliability to various customer groups. Most of these estimates are also based upon indirect indicators of customer losses. Although the results of these estimates are not directly comparable because of differences in the scope and dollar value of each, an order of magnitude variation exists among the various approximations of the customer's interruption losses.

The U.S. Department of Energy, Division of Electrical Energy Systems (DOE/EES) and the Electric Power Research Institute (EPRI) are now in the initial phases of efforts related to electric utility system reliability. Both EPRI and DOE/EES are developing methodological approaches for the quantification and analysis of utility system cost, reliability and customer valuation.

The study found to be most appropriate for quantifying the value of electrical supply reliability is the consumer survey activity underway by Ontario Hydro. This Canadian utility has intitiated a series of five detailed surveys to estimate the customer's losses resulting from various power interruptions and to identify customer preferences with respect to duration and frequency of outages. The results of only one survey, that of large manufacturers, are now available. Preliminary data on four other customer groups are available, but final results may not be known for several months. The four customer groups include small manufacturers, residential customers, farm customers, and other general rate class customers, including commercial and institutional users. Table 1.2 summarizes some of the aggregate customer losses as based on Ontario Hydro's surveys.

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*Two of these studies, Telson (1972) and Kaufman (1975), have computational errors; Kaufman's work also employs several unsupported assumptions. These have a significant effect on the conclusions reached in the original works, and have thus been accounted for in reporting this range. See Sections 3.1 and 3.4 for additional detail.

Table 1.2. Aggregate Customer Losses

Outage Duration	Large Manufacturers		Small Manufacturers[a]		Residential Sector[a]	
	$/kW	$/kW/hr	$/kW	$/kW/hr	$/kW	$/kW/hr
1 min	.60	36.00	.85	51.00	--	--
20 min	1.80	5.40	2.77	8.31	0.03	0.09
1 hr	2.67	2.67	4.39	4.39	0.03	0.03
2 hr	4.60	2.30	--	--	--	--
4 hr	6.02	1.51	19.92	4.98	0.06	0.02
8 hr	8.83	1.10	31.50	3.94	--	--

[a]Preliminary, subject to change.

-- Outage duration not sampled in survey.

Based on the comprehensiveness of Hydro's large industrial customer survey and preliminary results from their other surveys, it appears that this work is the best available empirical data on perceived customer losses resulting from electrical power interruptions. Hydro's survey work will ultimately address a wide range of individual customer groups and will apparently address nearly every important factor determining the customer's cost of electrical power reliability. Of course, Hydro's data are not directly transferable to other service areas. However, because of the level of disaggregation, it would seem possible to develop a methodology that would allow the transfer of customer loss relationships to other utility service areas.

Two other surveys, one by Consumers Power Company (CP) and the other by General Public Utilities (GPU), were also reviewed. Both of these surveys are of interest because they provide perspective on customer reaction to power interruption, but unfortunately are limited in any attempt to quantify the customer's value of reliable service.

1.2 CUSTOMER CLASSIFICATIONS AND COMPONENTS OF VALUE

Each customer has a unique set of electric energy requirements and level of incurred losses resulting from an interruption of service. These vary widely even among customers engaged in nearly identical activities.

Therefore, any attempted aggregation of customers will reflect this wide variability. The value to a customer of reliable electric power is dependent upon his service requirements and perceived interruption losses. These, in turn, are functions of a number of independent factors, including equipment design, availability of emergency back-up generation, ambient weather conditions, time of day or year, geographic factors, and others.

It is not practical from the viewpoint of national policy evaluation to attempt to quantify the characteristics of individual customers and service areas. Nor is it sufficient, because of the diversity in service areas and customer mixes, to use the broad customer value indices that have been used in the past. The most practical approach is to classify customers into a manageable number of groups defined by general electricity-use characteristics and values of electric service reliability. Such aggregations should facilitate both data acquisition and the modification of existing data to conform to different customer mixes and service areas.

A reasonable disaggregation of customers includes the following groups:

1. Large Manufacturers,
2. Small Manufacturers,
3. Commercial,
4. Institutional,
5. Agricultural, and
6. Residential Customers.

These groups are listed in the general order of decreasing individual customer demand and increasing periodic load variation. Large manufacturers are characterized by a generally high and uniform demand for electric power. Residential customers are characterized by fairly low demand per customer that may vary daily or seasonally by as much as 50 to 80% or more.

The value of electric service reliability to customers must be at least as great as the product of expected economic losses caused by a service interruption and the probability of that interruption occurring, summed over all possible interruptions. However, the customer's value of reliability may be greater than this computation would indicate because of certain external, or non-dollar costs, that are incurred as a result of electrical service interruptions. Examples of external costs include effects on the customer's comfort, convenience, or safety, but may also include indirect customer costs such as the release of environmental pollutants due to inoperable pollution control devices.

It is often difficult for both the customer and utility analyst to quantify and thus assign a value to external costs. However, these costs may be the most important factors in decision-making for some individuals. Despite the difficulty in assigning values to external costs (or benefits), the customer does so, at least implicitly, for every product that is purchased. Thus this component must be recognized, to the extent possible, in determining the customer's value of reliability.

Key constraints to assigning values to electric service reliability by customer groups are the wide variability and large uncertainty associated with operating environments and interruption costs as well as those of external costs. Much of the ongoing work, particularly by Ontario Hydro, is seeking to narrow the bands of uncertainty of the customer's internal costs.

1.3 OPTIONS FOR ALTERING SERVICE RELIABILITY

Numerous operational and technical options are currently or may potentially be available to alter customer service reliability relative to the level nominally provided by the utility. Each option may be classified according to whether it is selected by the utility or customer during the design phase, and whether it is activated by the utility or customer during day-to-day operations. The various options include:

Class A: Customer selected during design phase --
Customer activated during operation phase

1. Supplemental emergency power generation
2. In-house generation with utility backup
3. Storage devices
4. Voltage regulators and "uninterruptible" power supplies

Class B: Utility selected during design phase --
Customer activated during operation phase

1. Customer peak demand charge
2. Time-of-day pricing
3. Voluntary public appeals

Class C: Customer selected during design phase --
Utility activated during operation phase

1. Interruptible service contracts
2. Pulse-controlled devices
3. Special supply provisions

Class D: Utility selected during design phase -- Utility activated during operation phase

1. Generation reserve, configuration and interties
2. Transmission configuration and design
3. Distribution configuration, design and maintenance
4. Operational procedures

Some cost is associated with each option available for altering customer service reliability. Depending upon the type of option, its cost may be borne by the utility or by the customer either directly or indirectly through the utility rate structure. The cost relationship between reliability and equipment options such as emergency power generators, special supply provisions and generation, transmission, and distribution subsystem design are relatively easy to quantify for a particular customer or utility. A generic estimate of these relationships, however, is complicated by the wide diversity of customer requirements and utility system designs and practices. Nevertheless, the cost associated with each of the options available for altering customer service reliability is intimately related to the customer's perspective of value and willingness to pay for a specified level of utility reliability.

Other considerations enter into the customer's electricity requirements and value of electrical service reliability. Most notable is the option to use a different power source such as natural gas for process heat, or steam for mechanical drives. Another option includes a process designed for temporary or decreased (but continued) operation in the event of an electrical power failure. The extent to which these options are available will affect a customer's value of electric reliability because they will tend to decrease losses during electrical power interruptions. The options have not been included above because they do not alter the customer's electrical service reliability, but affect his ability to continue operations despite power interruptions.

1.4 POLICY

A variety of policy issues are directly or indirectly related to utility system and customer service reliability. A major area of current interest to DOE is the system integration effects of new technologies, particularly decentralized energy technologies (DET). DETs are both electric and non-electric energy sources that are small in comparison to today's centralized generation facilities, and which may be located near a load center or end-user. These systems may rely on conventional fuels or on renewable energy sources such as direct and indirect solar energy.

Major issues that need to be resolved, if DETs are to be successfully implemented, are associated with their optimum arrangements in terms of ownership and control, and the operational effects of these systems on society's energy infrastructure. DETs that rely on intermittent renewable resources such as direct solar conversion and wind generation will have a component of availability that is dependent upon prevailing meteorological conditions. The extent to which the supply intermittence may correlate with customer demand or affect the customer's service reliability and incurred costs is largely unknown.

Other major problem areas and issues that may arise, or that have arisen, in association with electrical reliability are related to the following areas:

1. Rate relief and rate structure,
2. System design and planning practices,
3. Utility price and service responsiveness to various customer classes,
4. Appropriateness of reliability assessment methodologies,
5. Load shedding priorities and customer equity,
6. Emergency power pricing criteria,
7. Long-term economic impacts,
8. Derating of generation facilities for environmental causes, and
9. Relative costs and benefits of a national transmission network.

1.5 CONCLUSIONS

A review of existing and ongoing studies of the value of electrical service reliability to the customer has shown that many of the past efforts take the form of indirect estimates. These studies attempt to quantify the value of reliability in terms of aggregate economic indices which are insensitive to regional variations in customer mix and which do not account for the customer's sensitivity to voltage reductions and the frequency or duration of interruptions.

More recent work seeks to quantify less aggregate customer losses through the use of customer surveys. Although a more disaggregate quantification of customer losses is far superior to the use of a single social or economic index, problems associated with the generalization of these data and their transferability to demographic areas outside the survey region exist due to unique customer, load, and other characteristics of each utility service area.

Ontario Hydro's recent customer survey data have been found to be most appropriate for future efforts in national and regional evaluations of electrical service reliability. These data on customer losses can likely be modified so as to conform to different customer mixes and service areas using readily available regional or local economic and demographic information. If these data should remain substantially unchanged with time, conclusions about reliability might easily be made when translated to U.S. service areas.

The customer's value of electrical service reliability depends not only upon his expected economic losses resulting from an interruption of service (internal costs), but also upon his perceived external or non-dollar costs. These costs are difficult to quantify but may be the most important factor in the value systems of some customers. None of the previous nor ongoing studies will provide data sufficient to quantify the value that customers assign to external costs associated with power interruptions. Thus, it is expected that adequate data related to the external cost component of value will remain deficient for some time.

Numerous operational and technological options for altering service reliability on a systemwide or more selected basis have been identified. The current or future availability of these options will affect the customer's willingness to pay for the level of reliability provided by the utility. A generic estimate of the customer's and utility's costs and benefits associated with any of the identified options is complicated by the wide diversity of customer requirements and utility system designs and practices. The evaluation of some options is further complicated by a lack of quantitative data as to their effect on the utility's system and customers.

Numerous local, regional, national, and international issues are related to questions concerning electrical supply reliability. Of particular and current interest to the U.S. Department of Energy is the system integration effects of new decentralized energy technologies, primarily those dependent upon renewable resources, such as solar conversion and wind generation.

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2 OBJECTIVES AND BACKGROUND

The general subject of reliability of electrical service from the customer and utility points of view is under inquiry. Service reliability is defined as the level of continuity and quality of electric supply to a utility customer's end-use device. Questions typical of those currently being asked by customer groups, utility commissions, utilities, and policymakers include:

1. What are the social costs and implications of having different electric supply reliability criteria?
2. What are the reliability preferences of various customer groups and how can a utility system be tailored to meet those preferences?
3. How will new intermittent supply technologies interface with the utility system and how will these affect customer reliability and utility planning?
4. What are the costs and benefits associated with reliability alterations in the generation, transmission, and distribution parts of the supply system?
5. How are various levels of reliability valued by diverse customer groups and what are the functional relationships between value and expected customer interruption frequency, duration, and geographic distribution?

In general, this report represents a review of work related to these and other questions on the value of electrical reliability to the customer.

The objectives of this paper are (1) to present a brief review of the literature and of current efforts that quantify the customer's value of reliability, (2) to provide an initial structure for customer classification, (3) to set forth a list of options for altering customer reliability, and (4) to identify some policy implications related to electric utility reliability. This document should be viewed as the first reporting of current ANL efforts on electrical reliability for the DOE Office of Technical Programs Evaluation.

Investigations of electric service reliability can be separated into those considering the supplier's views and those considering the consumer's views. Excluding secondary impacts from loss of electrical service, one can specify the proper reliability criteria for design by balancing the supplier's marginal costs to change reliability against the customer's costs for the same change in reliability. The customer can choose of course from numerous available supply options the one most economically justified, such as the purchase of backup equipment, as well as options provided by the utility. Before discussing consumer values and options, a short discussion of the electric utility system design practices will provide perspective on some important aspects of reliability.

Historically, electric utilities have approached generation, transmission, and distribution reliability planning as separate and sequential functions. Although most utilities have some criteria to which system expansion is designed, no apparent supportive cost/benefit analysis is generally used to justify the selection. Rather, system reliability target goals have often been a matter of utility policy or engineering practice established through long-term use.

Reliability planning for generation facilities is generally much more advanced than it is for transmission or distribution facilities. This priority is assigned because of several reasons: first, generation facilities are usually the largest individual cost investment of the utilities; second, a failure to have sufficient capacity available to meet the aggregate customer demand can potentially affect the entire utility service area; and third, the generation sector is easier to analyze because the facilities can be considered as a collection of point sources with forced outages dominated by the probability of mechanical failure. (Transmission and distribution facilities need to be considered as line sources with failure incidents partially dependent upon the geographic distribution of customers and on environmental exposure.)

Generating capacity reliability is usually discussed in terms of the sufficiency of capacity to meet total peak demand. In the past, it was the practice to provide enough capacity to supply the estimated peak demand plus an additional amount equal to some percentage of that demand, equal to the largest generating unit, or largest two units, depending upon the utility. The total capacity then exceeded the projected greatest electrical demand by an amount (reserve margin) that was supposed to allow for generator failures, for underestimating the load, and for extended maintenance work.

In an attempt to develop procedures more rational than rule-of-thumb methods, the power industry began to use probability analysis to compute their required capacity. Generation loss of load probability (LOLP) is the expected fraction of time that system generation will not be sufficient to meet estimated customer demand. LOLP is generally calculated on an annual basis of 365 days or sometimes based on 260 weekdays per year. A fairly common LOLP criterion adopted by most utilities that use this technique is one day in ten years or on an LOLP of 2.74×10^{-4} assuming a 365-day period.

First introduced in the 1930s, probability methods have now been developed to the point where most utilities use them to factor into capacity planning relevant information as to load patterns, number and size of generating units, forced outage and maintenance of individual units, and delays of unit construction. Probability analysis allows the planning engineer to determine the capacity needed to satisfy specified levels of reliability through consideration of such aspects as the frequency and duration of generation outages and the probability of the occurrence of outages, of positive reserve margin, of energy deficiencies, and of various levels of capacity shortages.

The reason for the greater complexity of reliability evaluation of transmission facilities over that of generating capacity lies in the inherent nature of transmission itself. Transmission lines connect specific points, and may be connected in many different patterns, each of which may need to be evaluated in terms of its level of reliability. They also perform such functions as bringing power from the generating plant to the demand area, connecting power plants and substations together, connecting systems together for sharing jointly-owned or reserve capacity, emergency transfers of power, and sales of capacity.

Transmission lines (overhead or underground) must be designed with a number of factors in mind and for the terrain traversed. Wind forces, icing conditions, river crossings, soil conditions, lightning storm intensity and frequency all play a part in the engineering decision for the towers, conductors, tower spacing, and other factors that ultimately affect the transmission system's reliability.

Reliability analysis of transmission is generally both a system and a point-by-point process that looks at every station supplying load to customers and takes into account every connection between stations. System planning usually provides alternative and supplementary paths for flow of power from generating plants to substations, between substations, and between utilities. However, as in the case of generation reliability, the customer reliability criteria designed into transmission facilities is often based upon rules-of-thumb that have been practiced by design and planning engineers in the past.

The distribution system moves power from a point on the bulk power transmission system to specific users of electricity. A lower level of reliability is often tolerated in distribution facilities than in other parts of the system because distribution failures affect only a small number of customers, whereas failures in generation and transmission may affect larger numbers. The probability of a utility experiencing a distribution line failure is usually greater than for a transmission line failure because of the greater number of such lines. Thus, most of the customer outages are caused by failures in the distribution system.

Long-range planning is usually not required for construction of distribution facilities to the same extent that it is required for large generating units and transmission lines. Distribution circuits and equipment are individually much less costly, they have shorter lead times for construction, and can generally be repaired or replaced much more rapdily. On the other hand, the number of distribution circuits and facilities is much greater and offers more geographically widespread occasions for failures and undesirable performance.

Customer reliability from distribution is generally controlled by using varying degrees of sectionalizing and automatic control and reset devices. Most utilities have no rigorous method for determining distribution reliability. According to a large Wisconsin utility, "Distribution substations and feeders are designed by 'seat of the pants' methods without any predetermined calculation of reliability. We assume that adequate service is being provided if service interruptions are not excessive and customer complaints are kept to a minimum."[1]

This Wisconsin utility, like many others, is studying the possibility of utilizing distribution voltages that are higher than those now in use in their system. Higher voltages will mean additional load and customers per feeder line as well as extended lengths of lines. The reliability level proposed for their new design is roughly that level being experienced by their customers as derived from historic records. The theory is that customer satisfaction will be maintained if their present level of distribution reliability is not altered.

Whereas the utility approach to designing electrical systems to desired reliability criteria is understood, the estimation of reliability criteria suitable for individual customers or for classes of customers is not well founded. This shortfall is due partly to the multiple values that the customer places on various uses of electricity and partly to variation in values among customers of even the same class. Generating system reliability and associated costs for various levels of reliability have entered into facility design for 40 or more years. The quantification of the customer's value of reliability has been developing only within the last decade. Indeed, the various investigators of customer value have used different measures to allocate cost for loss of service.

The customer's loss, or loss function, might be expressed in various forms. One is to express the losses as a function of the energy (kilowatt-hours) not used. In this instance, a simplified expression of cost for the lost electrical generation is some constant times the energy not provided during the outage. Another functional form is the expression of loss in terms of the peak demand (kilowatts) that might be provided during a period or season. Another approach is to express the loss in terms of the duration of the outage; the loss increasing as the duration increases. Some existing information confirms the validity of this latter approach. The form of the relationship for the loss may be linear or exponential in duration. From data accumulated through customer inquiries, it has been observed that customers are concerned with frequency as well as duration.[2] To some extent the inclusion of frequency may represent an experience factor, e.g., an outage of one or two per year is tolerable and the customer feels no need to reduce the rate, but an outage rate of three per year would justify expenditures to decrease the rate to one or two per year. Each outage of a specified duration in this example does not represent a fixed cost to the customer. The quantification of the frequency effect is not found in the ongoing studies.

Like most actions that affect society, the loss of electrical service by the customer can cause internal as well as external losses. Noncustomers can experience losses, e.g., someone using the products manufactured in a plant that loses electrical service may have to bear costs because the plant is unable to supply the needed product. In addition, there are the environmental and health costs associated with unreliable services. These costs in most instances are not included in the internal costs. The literature in most cases does not provide records of such costs.

Some of the literature provides information on customer's loss functions, but it is not known how representative these customer loss functions are. One of the ongoing efforts of ANL's activities in reliability is to establish a reference U.S. utility system in terms of both the supply network and the number and classes of customers. This reference system is necessary to explore the electrical supply costs and costs for loss of service to customers at various levels of reliability. In general, one would expect that the magnitudes would vary among utilities even though a certain class of customers had identical electrical consumption. Nevertheless, the synthesis of a reference U.S. utility system and its customers will advance the state of existing analyses. With such a reference classification, it will be possible to rank the classes of customers that benefit from various levels of reliability and to balance customer values against utility values.

At present, most customers contract for standard electrical service. For example, very few customers have interruptible power contracts. It is possible for customers to increase reliability by either special arrangements with the utility or by installing their own emergency and backup electrical systems. These ownership options might not be exercised if the utility were to provide comparable services. A portion of this report discusses the options that could be available to the customers to change their service reliability in order to accommodate their particular needs. The costs for each of these options are not included in the discussion.

The development and ultimate commercialization of small, dispersed electrical generation systems that utilize renewable resources such as direct solar, wind, low-head hydro, biomass, and others, may have significant impacts on electric utilities and their industrial, commercial, and residential customers. Many reliability-associated impacts are likely to be a result of integrating decentralized, intermittent capacity into existing supply networks. Impacts not only will be of a technical and economic nature, but may also include customer preferences, legal, and institutional issues. The purpose of present efforts by the DOE Office of Technical Programs Evaluation is to evaluate the potential system integration effects, and, in particular, the effects of decentralized renewable energy technologies considering the objectives of major stakeholders -- the utility and its various customer groups.

This report first reviews the state-of-the-art analysis and data on the customer value of reliability. This section is followed by a discussion of suggested classifications of customers. A section on options to alter customer service reliability by both customer and utility actions is then presented. Finally, some policy considerations relating to reliability are briefly described.

2.1 REFERENCES

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2. *Ontario Hydro Survey on Power System Reliability: Viewpoint of Large Users*, Ontario Hydro Report No. PMA 76-5, Toronto (1976).

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3 ELECTRIC UTILITY RELIABILITY STUDIES

Efforts have been made in the last decade to estimate the customer's value of electric service reliability. Generally, this value is assumed to be equal to the customer's losses incurred during a power interruption, and losses are assumed to be represented by indices such as gross national or regional product, wages and salaries or value added by manufacture in direct proportion to the electric energy (kilowatt-hours) not served due to a power interruption. Some estimates also quantify value in terms of a customer loss component proportional to the customer's electricity demand (kilowatts). These "steady state" estimates assume the same value for electrical service whether or not the customer is receiving power or experiencing an interruption. Others have pursued a variety of customer surveys to estimate the customer's losses; and yet others are founded upon theoretical economic models.

Usually, the underlying purpose for these estimates is to derive an optimum level of electric utility (usually generation) reliability by balancing the customer's losses against the utility's costs associated with certain levels of utility reliability. This section reviews many of the previous studies undertaken to quantify customer value of reliability. The works most frequently referenced and others most useful for future efforts have been reviewed in some detail. These reviews cover a reporting of the estimated customer value as well as a description and critique of the major assumptions and processes contained within each of the studies. For completeness, the results of other more limited estimates of the value of reliability to the customer have also been reviewed and tabulated.

3.1 TELSON, 1972

One of the earliest and most frequently referenced works in the area of electric utility system reliability valuation is that of M.L. Telson.[1] In his 1973 MIT Energy Laboratory report entitled The Economics of Reliability for Electric Generation Systems and his doctoral thesis of the same title, Telson attempts to provide an order-of-magnitude estimate of a socially optimum level of utility system generation reliability. Results are based exclusively on New York Power Pool (NYPP) data modeled through a series of simplifying assumptions. These results are in disagreement with more recently available empirical data.

Much of the MIT report is devoted to a review of three quantitative measures of generation system reliability: loss of load probability (LOLP), frequency and duration (FAD), and loss of energy probability (LOEP). Telson selects the latter as being most useful for the purposes of measuring the benefits to the system's consumers due to the level of reliability because the FAD and LOLP concentrate on measuring the expected amount of time in the planning period in which there will be a generation deficit, without focusing on the seriousness of the events.[2]

LOEP is the expected fraction of system energy not served through loss of load incidents. The LOEP model uses the LOLP method and weighs each LOLP shortage by the proportion of energy not served. Since the fractions of energy unserved are smaller than the fractions of time spent in outage for each incident, LOEP will always be less than LOLP.[3] Although LOEP is less than LOLP, it is not proportional to LOLP for any system through time, since the system's load duration curve and unit forced outage rates are likely to change with time.

Telson's approach to finding a socially optimum level of generation reliability is to construct relationships for the cost of system expansion and for customer losses resulting from unserved energy as functions of system LOEP, C(LOEP) and L(LOEP) respectively. The socially optimum level of reliability is defined as that value of LOEP for which the sum of C(LOEP) and L(LOEP) is minimized.

System expansion costs, C(LOEP) are based on an NYPP expansion study that computed the present value cost of expanding a system over 20 years at different levels of <u>LOEP</u> by using unit additions of 600 MW assumed to be installed when the specified <u>LOLP</u> criteria is violated. NYPP's graphical output was fitted by Telson to give the following relationship between cumulative present worth of annual charges (1981 dollars) and LOLP:

$$C(LOLP) = \left\{34.5 - 0.75 \log_{10}(260 \times LOLP)\right\} \times 10^9$$

$$\text{for } 1/260 > LOLP > 1/26{,}000. \qquad (3.1)$$

A system expansion cost relationship, as a function of LOEP, was required. Telson's approach was to investigate several generation expansion strategies using a linear program technique to select the least present value cost system in each strategy. Each expansion began with a 20,000 peak MW system similar to that of NYPP and having a peak demand growth of 8% per year while maintaining the initial shape of the load duration curve. Each expansion strategy was initially subjected to a constant reserve margin constraint specified as a percent of peak load. Each system configuration was then analyzed by a probabilistic simulation model (PROSIM) to determine the LOLP and LOEP for each of six 5-year periods in each expansion strategy. (Telson's planning horizon is 20 years, but he uses 30 years in the cost optimization model to eliminate end effects.) It was found that maintaining a constant percentage reserve margin caused system LOEP to decrease from period to period. Further, that within reasonable limits, any period's reserve margin could be altered to arrive at a desired LOEP for that period without significantly affecting the LOEP for other periods in the expansion strategy.[4] Thus by utilizing a trial and error combination of linear programming and probabilistic simulation, Telson was able to expand optimally the generation system (in terms of cost) at various levels of LOEP held nearly constant throughout each expansion strategy. Since the PROSIM model calculated LOLP as well as LOEP, a functional relationship between these two values could be investigated.

An examination of the results of six expansion strategies lead Telson to conclude that, for the particular load duration curve used, there was a linear 20 to 1 relationship between LOEP and LOLP (i.e., LOLP = 20 x LOEP). Although recognizing that a linear relationship does not hold in general, Telson argues that it may be valid over certain ranges of LOLP and LOEP; his expansions covered a range of LOEP between 8×10^{-4} and 2×10^{-5}.

Telson claims that by substituting LOLP = 20 x LOEP (or any linear relationship) into Eq. 3.1 and differentiating with respect to LOEP results in

$$\frac{d\,(C(\text{LOEP}))}{d\ \text{LOEP}} = \frac{-\,(2.3)(.75)(10^{9})}{\text{LOEP}} . \tag{3.2}$$

Equation 3.2 is subsequently combined with the derivative of the customer loss function to solve for LOEP where system costs and customer losses are minimum. Telson's results are marred by a technical error in an incorrect formulation of d (C(LOEP))/ d (LOEP). The correct formulation of the derivative is

$$\frac{d\ (C(LOEP))}{d\ LOEP} = \frac{-\ (1/2.3)(.75)(10^9)}{LOEP} . \tag{3.3}$$

All other things being equal, the use of the proper derivative would alter the magnitude of Telson's final conclusions by more than a factor of 5.

It should also be noted that an examination of Telson's six system expansion strategies shows an average proportionality "constant" of about 27 with a standard deviation of 9.5 based on 36 pairs of LOLP and LOEP. If three strategies noted by Telson as having "reasonably close" values of LOEP for each expansion period are examined, the average proportionality constant remains about the same and the standard deviation decreases to 8.4. This fact is important because Telson later converts the derived optimum LOEP to an LOLP measure using a linearity assumption based on a proportionality constant of 20.

Telson proceeds to make a rough estimate of the customer loss function by assuming that losses are linearly related to unserved energy. He argues that the "linearity assumption is ... good over ranges of energy curtailment which are small relative to customer needs; i.e., if losses are great enough that it pays the consumer to obtain backup generation, the loss function saturates at this point. This does not seem to be a problem over the ranges of LOEP we ...investigate."[5]

To estimate this relationship Telson assumes that the percent of energy unserved causes a like percentage of total wages associated with the interrupted economic activity to be lost. He argues on one hand that the assumption underestimates attendant losses because the effects of a loss of load linger beyond the duration of the loss of load event. And, on the other hand, that "this function will overestimate losses because it assumes that consumers will keep their average output per kilowatt-hour constant throughout time whereas they are bound to become more efficient when they are reconnected thus reducing the losses calculated when using the linearity assumption."[6]

In computing the loss factor per kilowatt-hour interrupted, the assumption is made that all wages are related to the energy production that occurs during daytime hours.[7] Thus, the LOEP in Eq. 3.4 is the LOEP based on a 12-hour per day load duration curve, LOEP′.

The wage proportionality constant is based on a 1969 wage and salary figure for New York State of $55 billion. (Corresponding industrial and commercial consumption is $\sim$47 million MWh.) This figure is escalated at 4% per year to 1981 dollars. The present value of wages expected to be paid for 20 years past 1981 is then determined assuming a continued annual escalation of 4% and a discount rate of 8%. A value of $1200 $\times 10^9$ results. This is the proportionality constant for the same time frame for which C(LOEP) was determined. Thus, the consumer loss function becomes

$$L(LOEP') = 1200 \times 10^9 \,(LOEP') \text{ dollars.} \tag{3.4}$$

It should be noted that part of Telson′s justification for selecting an LOEP based model (over an LOLP or FAD based model) for customer losses "is that customer losses escalate in faster than linear fashion with respect to the length of the outage duration, and therefore the larger the mean shortage duration, the worse the system. However, as long as the mean shortage duration and energy loss is not excessive ... it does not really matter much if the outage time occurs in larger segments or in a greater number of smaller segments."[8]

If this were true, it would also be a justification that the loss function given in Eq. 3.4 is conservative in that it overestimates the customer′s losses. This may be a valid approximation for a limited segment of utility customers, particularly the residential sector. However, as is noted in the discussion of Ontario Hydro′s survey of industrial and commercial customers (Section 3.7), the consumer′s loss function ($/kWh) is a strongly decreasing function of outage duration, approaching an asymptotic value for outages of 16–24 hours duration.[9] On this basis, Telson′s premise conflicts with more recent empirical data. By assuming linearity and a wage-related proportionality constant, he attempts to provide a reasonably conservative (high) estimate of customer losses.[10] His assumptions, however, may actually lead to an underestimation of industrial and commercial losses resulting from service interruptions of $\leq$ 24-hour interruptions.

Another rather significant inconsistency exists in Telson's formulation of the consumer loss function, L(LOEP). He states,

> Note that we are relating losses to (energy unserved), and that a problem arises if we carelessly relate losses to system LOEP ... Most production takes place over the daytime hours; it would be incorrect to associate all wages to all kWh produced. For the sake of convenience, and for the purpose of estimating an approximate relevant factor, we will assume that wages are related to that energy production which occurs during daytime hours, and this is how we will compute the proportionality constant for L(LOEP) ...[11]

He goes on to note that the use of a 24-hour load duration curve and a 12-hour load duration curve (7:30 AM - 7:30 PM) will yield approximately equal measures of energy unserved, but that the use of a 12-hour curve will produce an LOEP that is probably twice as great as the use of a 24-hour load duration curve.

Telson's statement is not necessarily in error, since LOEP is the summation of all probabilities that energy goes unserved in a specified time period divided by the energy that would have been served if all customer demand had been satisfied during that same period. The rationale is that the majority of the total probability that energy goes unserved is a result of contributions during the peak period, the 12 daytime hours. Thus, the probability of energy going unserved is about the same whether a 12-hour or 24-hour period is considered. The LOEP, however, may be greater if the probability of energy unserved is divided by energy demanded by customers in the 12-hour period as compared to that of the 24-hour period.

The problem is that the LOEP′ in the customer loss function stated by Eq. 3.4 of Telson's argument, is an LOEP based on a 12-hour load duration curve. This function cannot be differentiated with respect to the LOEP specified in the system expansion cost function C(LOEP), since the LOEP of the of the cost function is presumably based on a 24-hour load duration curve. Thus, it appears that

$$L(LOEP) \simeq 2400 \times 10^9 \, (LOEP), \tag{3.5}$$

based on his argument that LOEP $\simeq$ 2 LOEP′.

Based on his assumptions (and formulations), the result of Telson's work is that the socially optimum loss of energy probability (LOEP*) for system generation capacity is

$$LOEP^* = 1.45 \times 10^{-3}. \tag{3.6}$$

He converts this result to a socially optimum loss of load probability (LOLP*) by multiplying by a proportionality constant of 20 and gets

$$LOLP^* = 2.9 \times 10^{-2}. \tag{3.7}$$

The LOEPs and LOLPs referred to by Telson are based on 260 weekdays per year, but can be converted to a 365-day basis by multiplying by 260/365, since almost none of the probability of lost load will result on the weekends. Thus

$$LOLP^*_{365} = 2.07 \times 10^{-2}. \tag{3.8}$$

Since the present 1 day in 10 year LOLP planning criterion is equivalent to

$$LOLP_{10} = 2.74 \times 10^{-4}, \tag{3.9}$$

Telson concludes that typical systems may be roughly 100 times more reliable than is economically optimum. This excess reliability factor is substantially reduced, however, if (1) the proper formulation of d C(LOEP)/d LOEP is used, (2) the average ratio of LOLP and LOEP is used, and (3) if Telson's own argument regarding L(LOEP) and L(LOEP′) is credited. A side-by-side comparison of the two calculations is presented below:

Telson's Calculation	*Corrected Formulation*
$\frac{d\,(C(LOEP))}{d\,LOEP} = \frac{-(2.3)(.85)(10^9)}{LOEP}$	$\frac{d\,(C(LOEP))}{d\,LOEP} = \frac{-(1/2.3)(.75)(10^9)}{LOEP}$
$LOLP = 20 \times LOEP$	$LOLP = 27 \times LOEP$
	$L(LOEP') = 1200 \times 10^9\ LOEP'$
	$LOEP' = 2 \times LOEP$
$L(LOEP) = 1200 \times 10^9\ LOEP$	$L(LOEP) = 2400 \times 10^9\ LOEP$
$\frac{d\,(L(LOEP))}{d\,LOEP} = 1200 \times 10^9$	$\frac{d\,(L(LOEP))}{d\,LOEP} = 2400 \times 10^9$

Set sum of derivatives equal to 0

$$\left.\frac{(2.3)(.75)(10^9)}{\text{LOEP}}\right|_{\text{LOEP*}} = 1200 \times 10^9$$

$$\text{LOEP*} = 1.45 \times 10^{-3}$$

$$\text{LOLP*} = \text{LOEP*} \times 20$$

$$\text{LOLP*}_{365} = \text{LOLP*} \times (260/365)$$

$$\text{LOLP*}_{365} = 2.07 \times 10^{-2}$$

$$\frac{\text{LOLP*}_{365}}{\text{LOLP}_{10}} = 75.5$$

or

$$\text{LOLP*}_{365} = 75.5 \text{ d/10 yrs}$$

Set sum of derivatives equal to 0

$$\left.\frac{(1/2.3)(.75)(10^9)}{\text{LOEP}}\right|_{\text{LOEP*}} = 2400 \times 10^9$$

$$\text{LOEP*} = 136 \times 10^{-4}$$

$$\text{LOLP*} = \text{LOEP*} \times 27$$

$$\text{LOLP*}_{365} = \text{LOLP*} \times (260/365)$$

$$\text{LOLP*}_{365} = 2.61 \times 10^{-3}$$

$$\frac{\text{LOLP*}_{365}}{\text{LOLP}_{10}} = 9.5$$

or

$$\text{LOLP*}_{365} = 9.5 \text{ d/10 yrs} \qquad (3.10)$$

Thus, without an examination of the possible uncertainties surrounding these results it might be concluded that, given proper formulation and application of Telson's assumptions, typical utility system generation reliability standards may be 10 times, rather than, as concluded by Telson, 100 times too high.

Further insight can be obtained by examining Fig. 3.1, a graphical representation of the C(LOEP), L(LOEP), and C(LOEP) + L(LOEP) functions plotted against generation system reliability, R_{365}, where $R_{365} = 1 - \text{LOLP}_{365}$.

The results shown are those based on the corrected formulation. The system expansion costs and customer losses are divided by the initial peak megawatts of the system (20,000 MW), as a scaling factor. As shown, the calculated economic optimum reliability level of 9.5 days per 10 years is centered in a very broad minimum that could easily vary anywhere from 5 to 15 days per 10 years.

Another way to analyze these curves is to assume some nominal absolute uncertainty in the value of the L(LOEP) and C(LOEP) functions. Even if the best cost and customer loss data were available, an uncertainty estimate of $\pm$ 2% would probably be unreasonably low. Yet even with this small uncertainty, the magnitude of possible error in the value of C(LOEP) + L(LOEP) at the calculated optimum reliability is $\pm$ \$30x/kW. This figure is enlightening in view of the fact that within the entire range of reliability shown (0.5 - 25 days/10 yr), C(LOEP) + L(LOEP) varies slightly less than \$40/kW.

It is interesting, too, to look at the average cost difference of expanding a system at the present reliability criteria and at the economic optimum. The 20-year present valued difference, based on a one day in ten year LOLP criterion and the optimum 9.5 d/10 yr LOLP, is about $0.75 billion. This is only 2% more than the optimum system that would expand at slightly in excess of $34.5 billion. By itself, this difference would cause only about a 1% change in the customer's bill, since only about half of a utility's capital investment is for generation. As Telson notes, since this average excess cost adds only a small fraction to the customer's electricity bill, the consumer may be sufficiently risk averse to pay the additional amount for the added level of generation reliability.

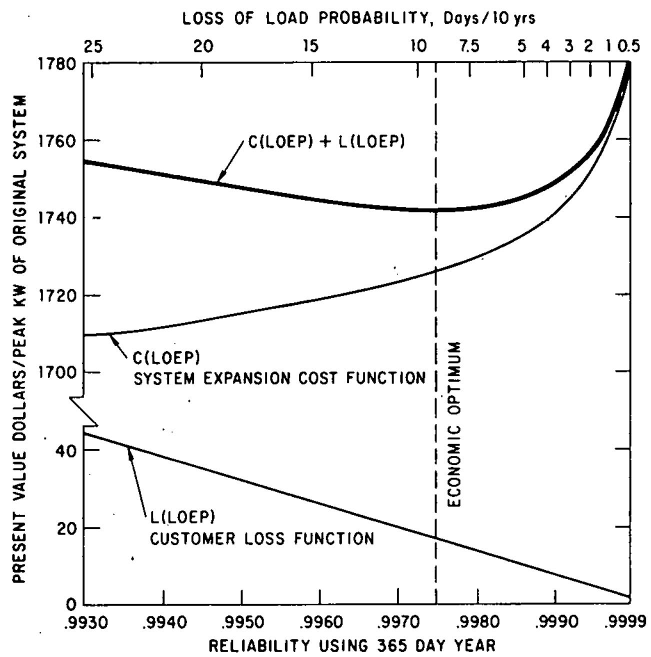

Fig. 3.1. Telson's System Expansion Cost and Customer Loss Functions (Corrected Formulation)

Source: Derived from Telson, M.L., *The Economics of Reliability for Electric Generation Systems*, Massachusetts Institute of Technology Energy Laboratory Report MIT-EL 73-106 (May 1973).

Although Telson's work has some flaws, his formulation plus the added analysis given here provide insight into the value of utility system reliability. The general shape of the curves discussed in Fig. 3.1 would seem to indicate that system generation costs increase at rapid rates for reliability levels better than 3 to 5 d/10 yr LOLP. Hence, with additional investigation, it may be possible in the future to formulate more substantial conclusions regarding the current 1 d/10 yr LOLP reliability criterion.

Because of very rough estimating techniques, Telson's conclusions are of little value as a source of data. And, since little or no mention is made of transmission and distribution reliability or cost, the work provides little assistance in investigating the effects of total system reliability on various customer groups.

3.2 TELSON, 1975

Another of Telson's works (perhaps more widely read) is a Bell Journal of Economics and Management Science paper published in 1975.[12] In the article entitled The Economics of Alternative Levels of Reliability for Electric Power Generation Systems, the author presents two upper bound estimates of consumer loss functions and adopts a somewhat different marginal cost approach to comparing generation costs and expected losses than is presented in his earlier MIT report.

His approach is to calculate the reduction in expected energy deficit made possible by the addition of one-megawatt unit (unit n+1) to a system at a given level of LOLP. The reduction in energy deficit by the addition of unit n+1 is simply the energy expected to be generated by this unit when it is assumed to be last in the loading order. Since the unit size is small, the expected megawatt-hours of energy generation in period k is approximated by

$$E_{n+1,k} = (P_{n+1}) \times (H_k) \times (LOLP_k) \times (1 \text{ MW}) \qquad (3.11)$$

where

P_{n+1} = 1 - forced outage rate of unit n+1,
H_k = hours in period k, and
$LOLP_k$ = loss of load probability in period k without the unit n+1 addition.

Expected generation over the unit's lifetime is discounted to the date of installation. This value, when multiplied by the current marginal net revenue from the sale of electrical energy, results in the total discounted sales revenue. Discounted sales revenue is then compared to the present cost of adding an additional megawatt of capacity; operating costs are neglected.

By Telson's calculations, lifetime generation from unit n+1 is 16.2 discounted megawatt-hours representing $480 of discounted sales revenue. The estimated cost to install an additional megawatt of capacity is $100,000. These results assume the following:

Unit Lifetime = 30 yrs

Discount rate = .10 per annum

Sales revenue = $30/MWh

P_{n+1} = 0.9

H_k = 360 hr = 260 d/yr x 18 hr/d ÷ 13 periods/yr

$LOLP_k$ = 1/2600 = 1 d/10 yr

Recognizing that most customers value energy lost at much more than its sales price, Telson makes two estimates of consumer losses. The first is a large upper bound estimate given by the ratio of the gross product of an area to the industrial and commercial electrical energy consumed in that area. He argues that this value is an overestimate of losses because (1) by excluding residential consumption in the denominator, residential losses are valued the same as industrial and commercial losses, given a power interruption; (2) through flexibilities of operation, customer disconnection will occur only after generation capacity falls by some margin below customer demand; and (3) some of the economic output is delayed or is only partially but not completely lost.

A smaller large upper bound on consumer losses is defined as the ratio of wages and salaries in a given area to the electric energy consumed by the industrial and commercial customers. This estimate is similar to that provided in Telson's earlier (1972) MIT Energy Laboratory report. He calculates this value for New York State and the total U.S., arriving at customer loss ratios of $1223 and $574 per megawatt-hour, respectively.

Since a $100,000 investment would produce 16.2 discounted megawatt-hours of electric energy, each discounted megawatt-hour costs $100,000/16.2 = $6170 to produce. Customer losses, in the absence of this energy, for the state of New York would be $1223 per megawatt hour unserved -- a factor of 5, less. Thus, Telson concludes that if LOLP levels were closer to 5 days in 10 years, the additional unit would be expected to generate more electricity, and therefore the cost of producing the additional megawatt-hours would more nearly equal the upper bound estimate of their value. He also suggests that since the national customer loss ratio (function) is so much smaller than the one for New York State, his conclusions may be valid in many other areas of the country, if not for most of the nation. It is emphasized that Telson's

1975 results approximate the results obtained from his 1972 work when the corrected formulation is applied.

Although it is not Telson's purpose to specify the desirable level of electric generation reliability, he states that it would seem possible to reduce generation system reliability target levels to perhaps a 5-day in 10-year criterion, while not seriously affecting the quality of service as perceived by most customers due to the much higher unreliability of the distribution network.

As with the earlier MIT report, Telson presents only a rough estimate of the value and cost of electric service reliability. He suggests that, whatever the generation reliability criterion, load shedding priorities should be determined beforehand so that in the event that load shedding is necessary it can be accomplished with a minimum of social losses. He makes no attempt, however, to identify what those priorities should be by estimating the loss function by customer group. Thus, with regard to present reliability questions, the 1975 study provides little insight over that of Telson's earlier work at MIT.

3.3 SHIPLEY, PATTON, AND DENISON, 1972

In an IEEE paper entitled Power Reliability Cost vs. Worth,[13] R.B. Shipley et al. adopt a somewhat different approach than M.L. Telson for estimating the optimum level of system reliability. The most important difference is that these authors take an integrated approach toward reliability (they refer to it as service availability) in that they consider not only the generation sector of the utility but also the transmission and distribution sectors. Second, their viewpoint is of the nation as a whole; hence they use national statistics and data to describe the power system. Third, the authors make an analysis of the service reliability for an average power system existing in 1967, rather than the approach of a planning perspective as used by Telson.

The authors are quick to acknowledge that the use of national data and their very rough approximations in formulating the problem render their results inapplicable to any specific utility or service region. Nevertheless, this concession does not detract from their primary objective, which was to "provoke discussion and further research into the cost of power interruptions and the optimizing of system design considering this cost."

Reliability, or service availability, is defined as the kilowatt-hours (energy) actually supplied to consumers divided by the kilowatt-hours that would be supplied if there were no service interruption. This concept can be related to Telson's terminology in that system availability is similar to 1-LOEP. There are some differences, however, in that Telson's approach is probabilistic and considers only generation reliability. On the other hand, although Shipley et al. make inferences from one year of statistics, they consider the entire utility system.

The authors' customer loss function is formulated under the assumption that production of all goods and services (GNP) ceases during a power interruption. For convenience in comparing customer losses with system costs, the loss function is expressed on a capitalized basis per kilowatt of peak load as follows:

$$\text{Customer Loss (\$/kW)} = \frac{\text{GNP}}{(\text{kW} \times \text{R})} (1-\text{A}) = 25,600\ (1-\text{A}) \qquad (3.12)$$

where

GNP = 1967 gross national product,
kW = peak load kilowatts,
R = carrying charge rate = 0.15, and
A = service availability.

They argue that in addition to the total value of the annual output of goods and services of industrial and commercial activity, GNP also reflects (at least to some extent) the nation's comfort, convenience, and safety. Thus, although a large portion of residential customer losses involve these secondary factors which are difficult to quantify, the use of GNP reflects their losses. The authors also emphasize that this expression is valid only for relatively small deviations from the level of reliability provided by present systems.

The authors also calculate the ratio of GNP to kilowatt-hours in 1967 and find a value of \$0.60/kWh. This value is somewhat lower than those estimated for industrial power interruptions in the United States (\$0.95-\$1.50/kWh).[14,15] However, these other estimates do not take into account portions of the GNP not affected by power outages. They state:

> It seems possible that some portion of the GNP would cease during a power interruption with resultant loss of goods and services. Other portions of the GNP might suffer additional losses due to spoiled product or damaged equipment. Finally, some portions of the GNP would be virtually unaffected by a power interruption.

Yet, they do justify the use of GNP as a <u>national average</u> customer loss measure by assuming that the additional losses from spoilage and equipment damage exactly balance that portion of unaffected GNP.

In constructing the owning and operating cost relationship of a utility system as a function of service availability, the authors make the assumption that the only factor influencing service availability is the degree of redundancy, and hence investment, in the power system components. Their methodology is reproduced in Appendix A. All operating costs are ignored for the purposes of the analysis, thus neglecting a very real cost contribution made by system fixed maintenance costs.

Shipley et al. begin by determining one point of this function that corresponds to the system design as it existed in 1967. Total reported investment in generation, transmission, and distribution in that year was obtained from Federal Power Commission (FPC) reports. Service availability of the bulk power portion of the system (generation and transmission) was also estimated from FPC reports of major power interruptions and total energy sales.[16] The service availability of distribution was assumed to be four times that of the bulk power system. Other points on the system investment curve were roughly approximated using the previously mentioned redundancy assumption.

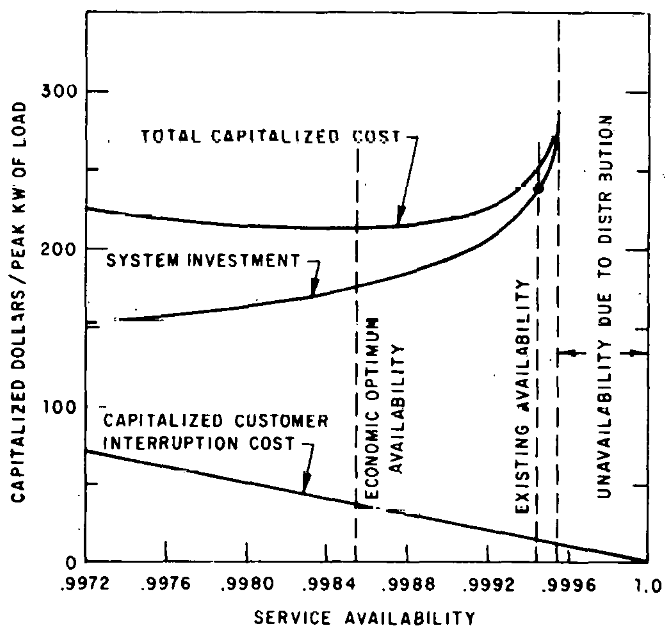

Fig. 3.2. Economic Optimum Service Availability -- Distribution Costs Held Constant

Source: Same as Fig. 3.3. source.

The authors' results are presented in Figures 3.2 and

and 3.3. In Fig. 3.2 distribution design, and hence distribution cost, is held constant. The ratio of generation and transmission costs is also held constant over the system cost versus availability curve. The economic optimum availability is shown to be somewhat less than the availability provided by the system design of 1967. They conclude that customer interruption costs would have had to be about \$5.50/kWh rather than \$0.60/kWh for the system design of 1967 to be the economic optimum design, which, they note, would not seem possible on an average basis.

Figure 3.3 is similar to Fig. 3.2 except that both generation and distribution costs are held constant and only transmission design and costs are varied. Here the optimum availability is closer to the availability of the 1967 system but somewhat less than that actually provided. If interruption cost was about \$1.60/kWh, the 1967 system would be the economic optimum. The authors also indicate that this value seems to be outside the range of possibility on an average basis. Based on approximate cost models, Shipley et al. conclude that power systems <u>may</u> (author's emphasis) be designed to provide excessive service availability.

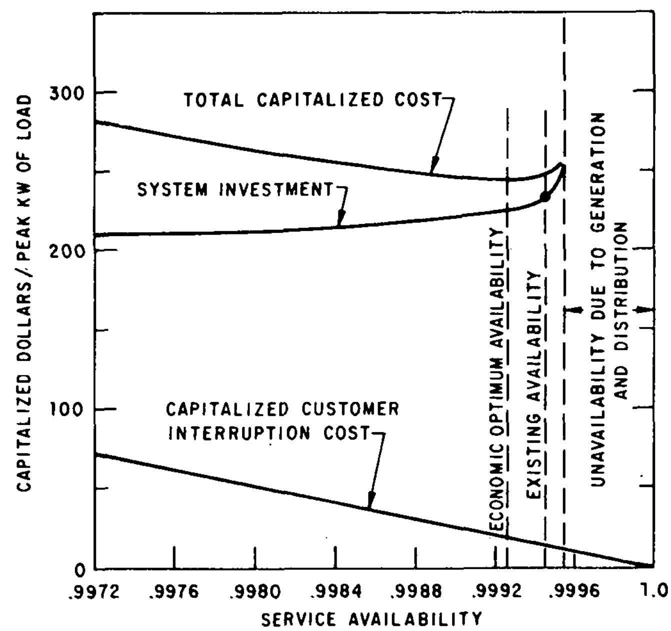

Fig. 3.3. Economic Optimum Service Availability -- Generation and Distribution Costs Held Constant

Source: R.B. Shipley et al., *Power Reliability Cost vs. Worth,* IEEE Transactions on Power Apparatus and Systems, pp. 2205-6 (July-Dec. 1972).

This work is interesting in that it is the only attempt found to address all segments of the utility system. It is, however, limited in that it analyzes only one operating year rather than taking a broader ranged probabilistic approach. Furthermore, the authors do not analyze, despite the ability of their model to do so, distribution costs versus the level of reliability.

The authors note that part of the cost associated with a power interruption results from effects on comfort, convenience, and safety, but do not attempt to quantify these costs in terms of customer's willingness to pay. Rather, it is argued that the use of a GNP-based loss function reflects these losses.

Although no attempt is made to quantify the loss functions of the various customer groups, the authors recognize that difficulties arise because of the rather large differences in the dollar value of electrical service continuity. Thus, this paper provides little in the line of disaggregate customer loss functions or the willingness of the various customer groups to pay for alternative levels of service reliability.

3.4 ALVIN KAUFMAN, 1975

As Director of the Office of Research of the New York State Department of Public Service, Alvin Kaufman prepared a document entitled, Reliability Criteria -- A Cost Benefit Analysis.[17] In this work, the author attempts to compare the costs and benefits accruing to the New York Power Pool service area between 1974 and 1985 at three levels of generation reliability. Kaufman selected loss of load probabilities of one day in ten years, five years, and one year for comparison.

While giving the illusion of a rather vigorous cost/benefit analysis, Kaufman develops his approach through a series of simplified and unsupported assumptions. Consequently, the methodology and results are of little value in present and future efforts concerning electric utility system reliability. A lengthy and detailed evaluation of Kaufman's work does not appear warranted in view of the nominal value of the author's methodology and results to future reliability studies. The interested reader is referred to the author's original work. Because of the frequent reference to Kaufman's report, and for the sake of completeness, a brief summary of the author's assumptions and methodology is presented in Appendix B.

In general, Kaufman erroneously estimates the cost of electrical service interruptions to the New York Power Tool to be $0.77/kWh in 1974 and $1.27/kWh in 1985. He concludes that a shift from an LOLP reliability criteria of one day in ten years to one day in one year would result in capital savings. The resulting electricity rate decrease would be minor, however, and may not be worth the inconvenience that would result. Unfortunately, the author's unsupported (perhaps unjustified) assumptions and some technical errors, generate a rather skeptical view of the validity of his results.

3.5 CONSUMERS POWER COMPANY, 1977

Consumers Power Company (CP) is an investor-owned utility headquartered in Jackson, Michigan. In 1976 CP serviced a total of 1.1 million residential, 121 thousand commercial, and 8 thousand industrial customers. Electrical sales in 1976 were 24.9 million megawatt-hours, and system generating capacity as of January 1, 1977, was 5897 MW. The 1976 winter system peak was only slightly larger than the summer peak at 4281 MW and 4185 MW, respectively.[18]

As part of an attempt to develop reliability standards to be used for economic system design, for planning system improvements, and for determining maintenance schedules, CP initiated a service reliability opinion survey.[19] The survey was conducted among residential electric customers through telephone interviews. Two different groups of customers were involved in the study. The control group was composed of customers who had not experienced an outage at home within one month. The outage group consisted of customers who were interviewed within ten days after they had experienced a power failure.

The control group was interviewed during December, 1975, and January, 1976. This group was included in the survey to provide a benchmark for answers given by the outage group customers; the final control group sample contained 430 customers. Customers were interviewed after it was determined that they had not experienced a recent outage.

The interviews of the outage group were conducted on a monthly basis from January through September, 1976. The outage group was divided into five duration categories as shown in Table 3.1. The duration categories were established to determine what effect the length of the power interruptions had on customer attitudes. Various criteria for selecting customers were established in an effort to sample customers with as much variance in outage exposure conditions as possible. The major criteria were that weather conditions and geographic location should vary, time-of-day and time of year should vary, and no <u>scheduled</u> outage should be included. The interviews were conducted up to ten days after the outage but not on the same day as the

Table 3.1. Outage Group Interruption and Sample Sizes

Duration Category	Interruption Length (Min)	Final Sample Size
1	2 - 89	284
2	90 - 179	263
3	180 - 299	224
4	300 - 479	173
5	480 or more	131

outage occurred. Only adults who had been at home at the time of the outage were eligible for the interview.

In general, CP's survey shows very little difference between the attitudes of the outage group customers and those of the control group. In most cases, differences in responses did not indicate statistical significance at the 95% confidence level. CP's conclusion was that "this tends to signify that the effect of a power interruption did not greatly irritate most customers. Customers who experienced an outage may have become more understanding of the fact that electric power may be lost on occasion through various uncontrollable circumstances. They apparently found out that they were able to cope with the situation."[18]

Significant findings with respect to control and outage group responses include the following:

1. In a question about the perceived seriousness of various durations of outages, there was a small difference in the ratings of hypothetical outages by the control group customers and the outage group. The outage group ratings were slightly less severe for all outages of less than eight hours. CP interprets this response as to indicate that after experiencing an outage, customers become more tolerant about loss of power.

2. In a question regarding frequency of outages, no statistical difference occurred among the control group and combined outage group in the number of power interruptions customers could accept in one year without being severely inconvenienced. Each group's response was nearly identical. Where responses differ, the outage group's responses are presented first:

Outage Duration	Mean Acceptable Number Per Year
≤1½ hrs	3.7
1½-3 hrs	2.8 & 2.9
3-5 hrs	2.1
5-8 hrs	1.6 & 1.7
≥8 hrs	1.2 & 1.4

3. Most customers did not favor an increase in electric rates to provide more reliable service nor did they want rates reduced with the likelihood of more power failures. A larger percentage of the control group customers were more likely to want to pay higher rates for better service reliability than the outage group (16.1% and 9.1%, respectively). Approximately 7% of the customers in both groups would favor paying lower rates with a chance of less reliability. There was no statistical significance with regard to group difference toward paying lower rates for less reliable service. There is, however, statistical significance regarding the two groups responses toward higher rates and better reliability.

The outage group was analyzed in many different ways to determine what type of conditions or circumstances were likely to change the attitudes of customers affected by power interruptions. Analysis was made by (A) the duration of the outage, (B) by the time of day the outage occurred, (C) by the season of the outage, (D) among customers who had experienced more than one outage, and (E) among customers of different types of communities. In many instances these different factors did have a slight effect on the attitudes and irritation levels as shown below:

A. Duration of Change

1. Customers who had experienced an outage of longer than eight hours consistently rated the seriousness of hypothetical outages less severe than did customers who experienced outages of shorter durations.

2. Customers who had experienced outages of over eight hours would be likely to accept more outages, regardless of length, than customers who experienced shorter outages. Customers who experienced an outage of less than 1½ hours would be likely to accept fewer outages.

3. Customers who had experienced outages of five hours or longer would be more inclined to want to pay

higher rates for more reliable service. Approximately 12% of these customers said they would rather pay higher rates to ensure more reliable service and fewer outages.

4. Customers having experienced longer outages mentioned more specific inconveniences through unaided recall than did customers who experienced shorter outages. Loss of heating, lighting, hot water, and cooking were mentioned most frequently among customers who experienced an outage longer than eight hours.

B. Time of Day

1. The time of day that the outage occurred had no significant effect on the seriousness ratings given to either the actual outage experienced or hypothetical outages of different situations.

2. No significant differences occurred in the number of outages customers would accept in one year in relation to the time the outage occurred.

C. Season

1. Customers who experienced outages in the winter rated the seriousness of the actual outage more severe than did customers who experienced outages in the spring or summer. This may be partly attributed to a greater incidence of outages of over eight hours included in this study that occurred during the winter.

2. Customers who experienced winter outages would accept more interruptions throughout the year than other customers. This again may be due in part to the greater incidence of outages over eight hours that occurred in the winter compared to the other seasons.

D. Multiple Outages

1. Customers were asked if they had experienced any additional outages within the year to determine the effect of multiple outages on attitudes. Customers who had two or more additional outages other than the one related to the interview rated the seriousness of their recent outage more severely than did customers who experienced only one other outage or no other outages.

2. Customers who experienced four or more outages would accept more shorter outages of less than three hours than other customers.

E. Community Type

1. Urban customers were likely to accept fewer outages of three hours or less in one year than rural, village, and suburban customers.

2. No significant difference occurred among customers living in different types of communities in relation to the seriousness ratings given to outages of different duration categories.

In general, the above results are qualitative representations of more detailed statistical tabulations presented in CP's report. These results are interesting in that they provide perspective on residential customers' reactions to various levels of power interruption as compared with those of a control group. However, except for one question related to the customer's interest in paying more for more reliable service or paying less for less reliable service, the survey does little to quantify residential customer's value of reliability. Even where customers expressed such interests, no attempts were made to quantify how much more or less the customer would be interested in paying.

It is also unfortunate that CP did not attempt to quantify the customer's out-of-pocket expenses or the existence of hazardous conditions existing in the home during the various power outages experienced by the outage group; these would have helped to quantify the non-dollar costs that residential customers incur.

Customer responses to several questions are counterintuitive. These, CP argues, can perhaps be explained by customers becoming more tolerant with power outages as they are subjected to increasingly more outages of longer duration. The result that customers who have experienced long outages would be willing to accept more outages (regardless of length) without being severely inconvenienced than those who experienced shorter outages may indicate that the customer's satisfaction with utility reliability is conditioned by their prior experience. This same subset of outage group customers, however, are also those who expressed more of a willingness to pay for more reliable service as compared to others in the outage group.

3.6 GENERAL PUBLIC UTILITIES, ONGOING RESEARCH*

General Public Utilities' (GPU) investigation in the area of customer effects resulting from power interruptions was self-initiated and resulted in response to the works by Telson, Kaufman, and Shipley et al., that were previously reviewed. In a report prepared for GPU by a research team from the Center for the Study of Environmental Policy, Pennsylvania State Univesity, it is argued that these works are "(1) underdeveloped regarding socioeconomic costs and benefits, (2) inappropriately directed toward broad national issues, (3) severely limited on the 'social' side of socioeconomics, (4) void of information on the cost of power interruptions from the viewpoint of the consumer, and (5) lacking in information on burden distribution among different socioeconomic classes."[20]

It is also argued that these studies provide an inadequate data base for coping with service-area-specific questions because of their use of aggregate national or statewide loss indices such as GNP, value-added, or wages and salaries. (This limitation is also explicitly recognized by the other authors.) GPU also notes other areas of inherent bias in these previous works in that the aggregate loss indices do not include the costs imposed on the household or residential sector and that they implicitly assume that future marginal impacts are equal to the average historical impacts.[21]

In an attempt to provide a satisfactory information base for service-region-specific policy setting, GPU, through contract to the Center for the Study of Environmental Policy, has initiated consumer surveys of three groups in the Reading and Altoona, Pennsylvania, areas.[22] Groups being surveyed include residential customers, industrial, and commercial customers (business), and community leaders. The use of the survey instrument is intended to

*General Public Utilities (GPU) is a holding company for three operating companies in New Jersey and Pennsylvania -- Jersey Central Power & Light Co., Metropolitan Edison Co., and Pennsylvania Electric Co. Through these companies, electrical services are provided to 4 million persons within a service area encompassing about half the land area of the two states. Megawatt-hour sales in 1977 total 30 million, with 35% going to residential sales, 23% to commercial, and 36% to industrial users. Fuel sources were 56% coal, 33% nuclear, and 11% other fuels. (*General Public Utilities 1977 Annual Report to Stockholders*, Reading, Pa.)

explicitly incorporate "the most important source of information on the value of reliability standards -- the consumer." It is also hoped that the surveys will provide a basis for showing the relationship between costs to individual consumers and synergistic social effects due to widespread outages.[23]

Each survey describes the following scenario and asks the respondent to answer between 10 and 22 questions:[24]

> In late July, the entire eastern half of the United States is caught in a heat wave. On Tuesday, July 31, the heat wave has already lasted three days. In the Reading area, the temperature at 8:00 in the morning is 90 degrees and by noon has reached 98 degrees. The humidity is 86 percent.
>
> At about 11:30 in the morning, the electricity goes off and the <u>entire</u> Reading area is without electricity until after 11:00 that night. In other words, Reading has no electricity for almost twelve hours.

Business and community leaders are told that this type of blackout is apt to occur on an average of once per year for the next ten years; residential respondents are not. Each respondent is told to keep in mind all the dimensions of their community that would be affected by such a blackout and to think in terms of <u>all</u> people in the community. Residential customers are reminded that:

> ...electricity provides energy for lighting, refrigeration, air conditioning, as well as for many other uses in your homes and businesses. It powers such things as elevators, street lights, fire alarms, traffic signals, water systems, sewerage systems, gas station pumps, and computers. Industries use electricity to power production. Hospitals are dependent, too. These are only a few of the many uses of electricity!

The residential customers are asked how they think such a blackout would affect various groups and activities or concerns in their community. To each question, the respondent may answer by checking: 1. very bad, 2. somewhat bad, 3. no effect, or 4. good effect. The respondent may also specify why that response was chosen. The questionnaire specifically asks how each respondent perceives the effect on:

Groups	Activities or Concerns
Elderly,	Public Safety,
High-rise residents,	People's fear of crime,
Residents in high-crime areas,	People's happiness with the community,
Low-income people,	Special activities -- clubs,
Middle-income people,	sporting events, etc.
Handicapped,	
Police,	
People like themselves.	

Residential customers are also asked to describe the major problem the community would face as well as the major problem they themselves would face. They are asked to estimate and describe their dollar losses and asked if they are satisfied with their electricity reliability over the past 12 months. In addition to standard demographic data such as housing type, age, sex, and income level, the respondent is asked how often they would be willing to put up with such a blackout. The choices are: (1) monthly, (2) annually, (3) once in ten years, and (4) never. Early responses show a very high percentage choosing once in ten years.[25]

Business leaders are asked a somewhat different series of questions concerned primarily with their perceived effects on their own business, employee safety, and general economy of the area. (It must be remembered that these respondents were told that such a blackout would occur on an average of once a year for ten years.) This group is also asked about their satisfaction with the present level of service reliability and to estimate their dollar losses.

Community leaders are asked to respond to questions that relate to project-specific effects as well as general community-related effects such as the economy, general quality of life, and people's satisfaction with the community and public safety.

The major thrust of GPU's survey activities is to determine the effect of a blackout on various social indicators, which are held by some sociologists to be expressions of the measure of the noneconomic dimension of social well-being. Examples of social indicators include attitudes toward job satisfaction, community services, personal health and safety, racial prejudice, and the like. Proponents of the use of social indicators hold that these indices balance economic measures that are relatively easy to quantify and to communicate and which are consequently accorded an exaggerated importance in social assessments.[26]

One problem arises from GPU's technique for measuring social indicators. The primary function of social indicators is to provide a statistical time series measure of social concerns.[27] This function requires the researcher to sample a population periodically by asking, "How do you now feel about that situation?" rather than, "How do you perceive a hypothetical situation as affecting you?," as is being attempted by the GPU study team. Consumers often perceive bad situations as worse than they actually turn out to be, whereas the effect of relatively minor situations might be perceived as being less of an inconvenience than they actually are.

GPU's results will perhaps give a qualitatively insightful perspective of a customer's aggregate perception of a particular outage scenario. It is debatable as to whether residential responses can be combined with those of business and community leaders, since the latter two groups' responses are based on their perception of having one 11½ hour outage each year, whereas the residential survey is based on a perceived isolated incident.

A major shortcoming in GPU's survey is that no attempt is made to quantify the willingness of various customers to pay to avoid the outage they describe in their questionnaire. (Nor is there an attempt to determine a customer's ability to pay.) Their questionnaire describes only one outage; they do not investigate a customer's perception of shorter power interruptions. Thus, their results will certainly be of limited value in ANL's present efforts.

3.7 ONTARIO HYDRO, ONGOING RESEARCH

Ontario Hydro is a publicly owned utility servicing the Province of Ontario, Canada. Hydro provides retail electrical service directly to large industrial and rural consumers, and wholesale service to 334 associated municipal utilities. System generating capacity is 18,700 MW, and total primary retail electrical energy sales in 1975 were just under 76.2 million MWh.[28]

In 1974 the Ontario Energy Board (Ontario's energy regulatory commission) conducted hearings on Hydro's rates. One of the major concerns was Hydro's large reserve margin, which resulted from decisions to build generating capacity when prevailing economic conditions showed a large growth potential in the demand for electrical energy.[29] Because of the Energy Board's decision that the aspect of system reliability ought to be investigated, Hydro initiated a program of studies that include the evaluation of alternative levels of reliability of power and energy supply from the viewpoint of selected customer classes and of the Province as a whole.

Under the supervision of the Power Market Analysis Department of Ontario Hydro, a series of five surveys were planned and initiated. These surveys cover the following customer groups:

1. Large manufacturers (>5 MW peak)
2. Small manufacturers (<5 MW peak)
3. Commercial and institutional (general rate class other than manufacturers)
4. Residential, and
5. Farm.

The only report available in final form is that on the large manufacturers. Preliminary data, based on partial returns, are available for some of the other customer groups. To date Hydro has not applied its results in any decision or policy issues within the utility. Rather its current approach is to limit efforts to data collection and statistical presentation of results.

3.7.1 Large Manufacturers

In general, the goal of Hydro's activities is to provide current and local data on the proper amount of the generation or distribution system reserves. Specifically, the large manufacturers survey was designed to:

1. Obtain customer estimates of costs and other effects of electrical energy supply interruptions, voltage variations, frequency variations, and energy rationing,
2. Gather data on industry groups for use in planning and operating the system, and
3. Obtain information for use in seeking consumer cooperation to reduce adverse effects of operating problems that might occur in the future.

This survey was initiated with a letter sent to all customers in the large user group. Ontario Hydro staff then visited each member of the group to deliver and discuss the questionnaire which was left with the customer for completion. Follow-up visits were made to expedite response. Customers with a total of 199 contracts were asked to complete questionnaires. There were

172 responses, which are considered representative of large users in terms of geographical distribution and type of industry. Hydro identified 24 industry groups, but in order to maintain confidentiality, the respondents were combined into 12 industry groups when reporting cost of interruptions.

The sum of the respondents' peak demands in 1975 was 3900 MW; their energy use in that year totaled 17,500 GWhr. This energy use is 87% of the total electricity consumption for all 199 potential respondents and about 25% of Ontario's electrical generation in 1975.

Among a series of other questions, respondents were asked to estimate the costs of interruptions for nine specified durations (<1, 1, 20 min, 1, 4, 8, 16 hr; 1 day; 1 week). In the questionnaire, cost of interruption was defined to include:

1. Cost because of loss of production,
2. Out-of-pocket expenses such as labor, materials (spoilage), overhead, cleanup, etc., and
3. Damage to production equipment, if any.

Reported cost estimates covered only the costs incurred by the user. They do not include any costs to the community such as unpaid wages, or the cost incurred by others because of delays in delivery. Respondents indicated confidence in their estimates ranging from 30 to 100%, the average being 74%.

Figure 3.4 presents the cost estimates for individual industry groups. Because the respondents varied widely in size, individual cost estimates would not indicate the relative sensitivity of each group (or respondent) to an interruption. The cost estimates for each group, therefore, were divided by the sum of the peak demands of the respondents in the group, producing an estimate of cost in $/kW of peak load. Other factors might be used for this purpose, but Hydro maintains that the use of peak demand at least partially eliminates the size factor and is a readily available value. For the industrial group, peak kilowatts is also a reasonable estimate of average demand because large industrial users' demand curves are relatively flat.

It is interesting to note the wide variations of minimum and maximum costs about the average cost lines in Fig. 3.4. In nearly every case, the range of cost estimates varies at least an order of magnitude above and below the average over a large range of outage duration.

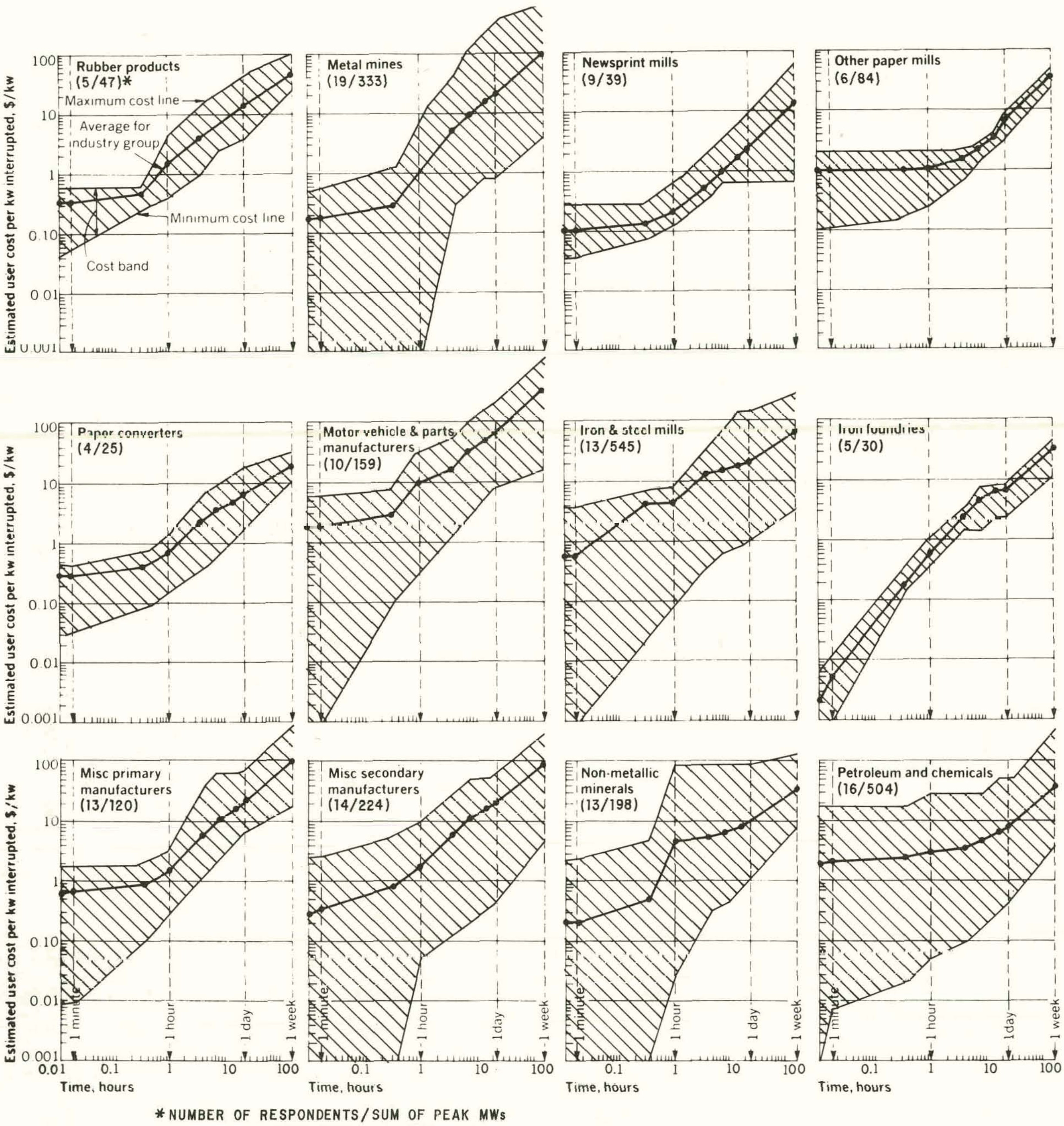

Fig. 3.4. User Estimated Cost of Interruptions by Industry Group ($/Peak kW vs Interruption Duration)

Source: *Electrical World*, July 15, 1977, p. 65.

Figure 3.5 shows the band of average user-estimated cost of interruptions versus outage duration. Also shown is the overall average cost as a function of outage duration. The wide variation in average costs corresponds to the wide variation of industry groups represented, yet it is encouraging to note that the industry group's average cost curves displays a well-defined characteristic shape.

Figure 3.6 shows a plot of the rate of change of overall average large manufacturer losses as a function of outage duration. As the figure indicates, the function is a strongly decreasing one for outage durations of less than 4-8 hours. An asymptotic value of approximately \$.50-.60/kW/hr* is approached as outage durations increase to greater than 20 hours. Because large industrial is charac-

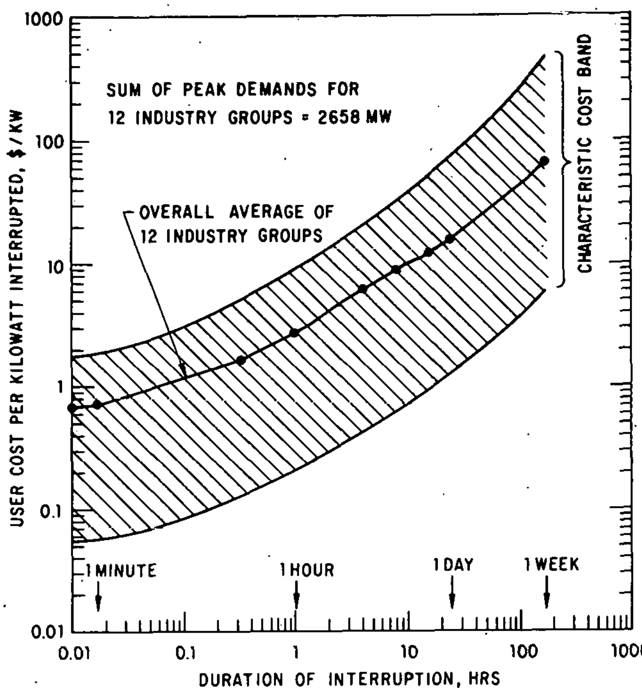

Fig. 3.5. User Estimates of Interruption Costs

Source: *Ontario Hydro Survey on Power System Reliability: Viewpoint of Large Users*, Report #PMA 76-5, p.. III-7 (April 1977).

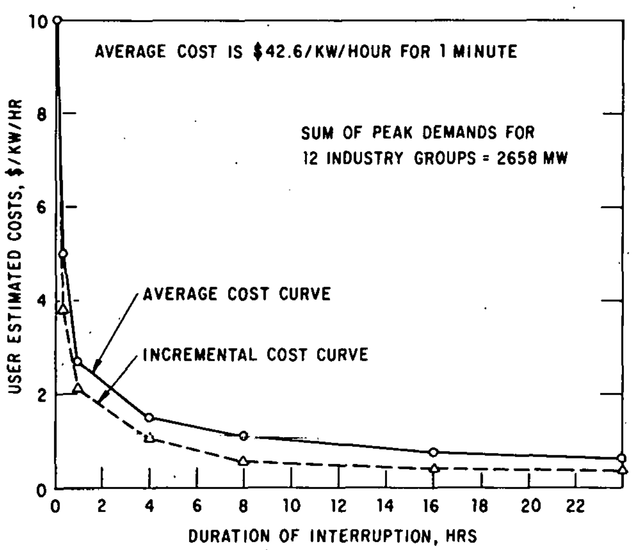

Fig. 3.6. Rate of Change of Interruption Costs

Source: *Ontario Hydro Survey on Power System Reliability: Viewpoint of Large Users*, Report #PMA 76-5, p. III-8 (April 1977).

*Dollar losses divided by peak demand (kilowatt) divided by outage duration (hours); strictly <u>not</u> dollar losses per kilowatt-hour unserved during interruption.

terized by a high load factor, the peak demand may be considered an appropriate approximation for the average demand. In this case, Fig. 3.6 may be interpreted as customer losses per unit energy (i.e., per kilowatt-hour), or approaching an asymptotic customer loss value of $0.50-0.60/kWh. Although not directly comparable because of different dollar values, it is interesting to compare this value with estimates made by Telson ($0.57/kWh) and Shipley et al. ($0.60/kWh) based respectively on ratios of wages and GNP to nationwide kilowatt-hours generated. However, as mentioned earlier, Ontario Hydro's results show the loss function approaching the asymptotic value from above and would, consequently, tend to rebut Telson and Shipley's argument regarding the use of asymptotic customer losses and average outage durations.

Ontario Hydro's survey of large manufacturers goes much further than quantifying customer losses. For example, the respondents were asked to indicate, over ranges of outage duration, the relative importance of inconvience, hazard, and dollar costs. Responses indicate that dollar cost, regardless of duration of interruption, is the most important factor, and that it became progressively more important with the duration of the interruption. Inconvenience was second when the duration was one minute or less; hazard took second place when the interruption lasted 20 minutes or more.

The survey sampled customers perceived losses as a function of frequency of interruption ranging from one/year to two/day, although the results are not published in their report. Losses are estimated assuming no advanced warning or with advanced warnings of one and two hours. The fact that about one-third of the customers felt that losses could be substantially cut if they were given advanced warning is published in the report, but the magnitude of loss reductions is not.

Another interesting survey result is the effect of voltage variations on customer production. Normally, utilities reduce voltages in steps, first 5%, then 8%. A 5% voltage reduction would curtail production activities of about 17% of the respondents, and an 8% reduction would curtail production activities of about 38%. The extent of the curtailments is not specified, nor was this information requested in the survey.

Industrial customers responded to additional questions too numerous to mention here. Some of these were concerned with the number of employees that would be laid off in various interruptions; others were concerned with interruptible loads and the customer's ability to segregate loads; still others sampled the customer's attitude toward electric power rationing and conservation, and the amount of standby capacity available for emergency generation. Regarding rationing, 118 out of 158 respondents preferred less frequent interruptions of the same total duration; 30 preferred the opposite; 10 were indifferent. The overwhelming preference by industrial customers for fewer but longer outages seems reasonable in light of the customer's loss function shown in Fig. 3.6. Note that this result contradicts customer preferences assumed by Telson and other previous investigators, who assume that interruption frequency is insignificant and has little effect on customer losses.

3.7.2 Small Manufacturers[31]

Only preliminary results based on 3574 usable responses to about 14,000 mail surveys are currently available. These should be viewed as tentative and subject to change.

The principal findings are as follows:

1. Small industrial losses range from \$0.27-\$1.90/peak kW for a momentary (<1 min) interruption and from \$0.90-\$6.53/kW for a one-hour interruption. Average values are presented in Table 3.2.

2. Only 194 respondents, or about 5.4%, had emergency standby equipment.

3. Start-up time for a one-minute interruption averages less than one hour.

4. A majority of respondents could tolerate a 5% voltage reduction. A 10% voltage reduction would cause curtailment of production for most respondents.

5. Eighty percent of the respondents reported that emergency interruptions would cause serious hazard to humans or to the environment.

6. Most respondents would prefer less frequent but longer interruptions rather than more numerous but shorter interruptions covering the same total duration.

3.7.3 Residential Customers

A marketing research house was contracted to process the residential questionnaires. Preliminary results are based on 1239 usable returns.

A hypothetical question was placed before each respondent offering them an alternative electric energy supply from an assured system without any interruptions. Respondents were asked how much more they are willing to pay for such a system, given interruption durations of their existing system of 20 min., 1 hr, and 4 hr per day. The answers given were in percentages of existing householders' bills, providing a relative answer but not an absolute one. The number of initial responses was very low. Accordingly, the survey is being repeated with clarification sought for the consumer's dollar value of the reliability of the system. Residential customers are currently paying about $0.02 per kilowatt-hour.

Highlights of the survey are:

1. A large majority of residential consumers prefer to have more frequent power interruptions but of shorter durations rather than fewer but longer interruptions covering the same total outage duration.

2. The perceived worst occasion for interruptions were: 5:00 to 7:00 p.m. and 6:00 to 8:00 a.m.; Sundays, Mondays, and Fridays; and during winter.

3. Under the condition of a 20-minute per day power interruption, half of the respondents had no interest in paying a premium for an "assured system." However, 25% said they would pay as much as a 10% premium for the assured system; few would pay more than that.

4. An 80% majority would choose the assured system at a premium of at least 5% if interruptions reached 4 hours per day; 50% at least a 10% premium; 25% would pay as much as a 20-50% premium.

5. Expressed interests in the premium rate assured system are interpreted as perceived customer losses due to interruptions. These are also presented in Table 3.2.

3.7.4 Farm Customers[31]

Over 6000 responses have been received from an initial mailing of 25,000 questionnaires to a sample of large farm accounts. Responses have not yet been coded, but a visual inspection of the returns indicate that many farmers can assign costs to interruptions and that they are aware of the consequences of a lower level of system reliability.

3.7.5 Commercial and Institutional[31]

Two groups in this rate class are being surveyed: retail trades and services, and governmental agencies and institutions. The retail survey has undergone several pilot tests. From these returns, Hydro is confident that many proprietors are able to determine their losses due to an interruption. Note that the data presented in Table 3.2 are not a result of preliminary returns, but rather are based on a theoretical approach developed by Stanford Research Institute (SRI). Hydro has indicated that available documentation of SRI's methodology is difficult to analyze and places little confidence in its output.[32]

3.7.6 Evaluation and Availability of Results

Based on the comprehensiveness of Hydro's survey of large industrial customer and preliminary results from their other surveys, it appears that their work is perhaps the best available empirical data on perceived customer losses resulting from electrical power interruptions. Their survey work will ultimately address a wide range of individual customer groups and, apparently, nearly every important factor determining the cost (or value) of electrical power reliability. Hydro's data is, of course, not directly transferable to

Table 3.2. User-Estimated Interruption Costs[31]

Outage Duration	Large Manufacturers		Small Manufacturers		Residential Sector[a]		Commercial Sector[b]	
	$/kW	$/kW/h	$/kW	$/kW/h	$/kW	$/kW/h	$/kW	$/kW/h
1 min	.60	36.00	.85	51.00	--	--	.02	1.20
20 min	1.80	5.40	2.77	8.31	.03	.09	.34	1.02
1 hr	2.67	2.67	4.39	4.39	.03	.03	1.03	1.03
2 hr	4.60	2.30	--	--	--	--	3.09	1.55
4 hr	6.02	1.51	19.92	4.98	.06	.02	5.15	1.29
8 hr	8.83	1.10	31.50	3.94	--	--	9.27	1.16

[a]Preliminary, subject to change

[b]Based upon a theoretical methodology developed by SRI for Bonneville Power Authority.[32]

-- Outage duration not sampled in survey other service areas. However, because of the level of disaggregation, it would seem possible to develop a methodology that would allow the transfer of loss relationships to aid in estimating costs for other areas.

It will be several months before Hydro's residential, commercial, and governmental survey results are available in final form. Results from the small manufacturer's survey should be available within about 2 months, and the farm survey results some time after that.

Since survey results are summarized only in the final reports, not all of the available data are as yet published. Hydro does not attempt to analyze the results they obtain, but present their findings in a manner that allows the reader to make his own evaluation.

3.8 EUROPEAN AND OTHER STUDIES

A number of other domestic and European studies that attempt to estimate the value of electric utility reliability have been published since the mid-1960s. Exclusive of a small 1973 IEEE survey of California industrial and commercial customers and some European surveys, most of these efforts estimate customer losses during service interruptions by indirect methods. These include wages lost per hour of outage, wages lost per kilowatt-hour associated with an outage, and gross national or state product lost per kilowatt-hour. Table 3.3 summarizes the methods and results of these studies.

The customer costs presented here are not directly comparable because of differences in the scope and dollar value of the estimates. Nevertheless, it is noted that many of the estimates vary by more than a factor of ten. In general, the greater number of customer cost estimates that have been made over the last decade are based on easily obtainable indirect indicators of customer losses. Only one of the domestic estimates shown in Table 3.3 is the product of a customer survey that attempts to quantify the losses as a function of outage duration (IEEE, 1973). The survey shows commercial sector losses per kilowatt-hour increasing with outage duration. On the other hand, Ontario Hydro's figures based on an SRI methodology, show commercial losses per kilowatt-hour relatively constant with outage duration. It is emphasized, however, that Hydro stresses the fact that their results are probably not accurate and that substantial differences may be present in their final results.[33]

Table 3.3 Methods and Results of Miscellaneous European and Domestic Value of Electric Reliability Estimates

Study	Method	Scope of Interest	Estimated Cost
Sweden, 1966 [a]	Survey	Swedish General Industry	$ .40/kWh + $.20/kW
Sweden, 1969 [b]		Swedish Domestic	$ .60/kWh
		Swedish Industrial	$ .30/kWh + $.08/kW
		Swedish Commercial	$ .80/kWh
		Swedish Agricultural	$ 1.20/kWh
		Swedish Transportation	$ .50/kWh + $.12/kW
		Worth of Goodwill	$.14/kW
		Total:	$ .50/kWh + $.20/kW
Norway [c]	Survey	Norwegian Industry Excluding Petroleum Melting Industries	$ .70/kWh + $.07/kW
Modern Manufacturing, 1969 [d]	-	United States General Industry	$ .95/kWh
Hausgaard, 1971	Wages/Hour	New York State	$ 2.17 million/hour
New York State Economic Development Admin., 1971	Wages/Hour	Central Manhattan	$ 2.5 million/hour
P.E. Gannon/IEEE, 1971 [e]	-	United States' Highly Automated, Low Demand Industry	$10.00/kWh
		United States' Less Automated, High Demand Industry	$ 1.50/kWh
Institute for Electrical, and Electronics Engineers (IEEE), 1973	Survey	California Maximum Industry	$ 2.68/kWh + $1.89/kW
		California Median Industry	$ .83/kWh + $ .69/kW
IEEE, 1973	Survey	California 15 Min. Commercial	$ 7.54/kWh
		California 1 Hour Commercial	$ 6.74/kWh
		California >1 Hour Commercial	$16.16/kWh
Environmental Analysts Inc., 1975 [f]	Wages/kWh	Wisconsin Industry & Residential	$ 1.00/kWh
Stanford Research Institute (SRI), 1976	Wages/kWh + Restart Costs	Northwest Power Pool, Short Term	$21 million/hour
		Northwest Power Pool, Long Term	$14.5 million/hour
		Northwest Power Pool, Long Outages	$ 1.36/kWh
National Economic Research Associates (NERA), 1976	GNP/kWh	United States in 1983	$ .61 - $1.20/kWh
D.J. Khazzoom/Stanford U., 1976	Gross State Product/kWh	California	$ .64/kWh
Federal Power Commission, 1976 [g]	GNP/kWh	United States	$ .50/kWh
Systems Control, Inc. [h]	-	California Residential	$ .10/kWh

a Mattsson, B., *Economy Versus Service Reliability in Sweden,* IEEE Spectrum, Vol. 3, p. 90 (May 1966), cited by Shipley, et al., in Ref. 13.

b *Costs of Interruption in Electric Supply,* Swedish report from Committee on Supply Interruption Costs (Sept. 1969), cited by C.R. Heising in response to Shipley, et al., in Ref. 13.

c C.R. Heising, personal communication, cited by Shipley, et al., in Ref. 13.

d Ref. 14.

e Ref. 15.

f *A Cost Benefit Approach to Capacity Planning for Wisconsin Utilities Service Area,* Environmental Analysis Inc., (Nov. 1975) pp. 27-28, prepared for Wisconsin PSC and Stern, G.B., Wisconsin PSC, personal communications (May 1978).

g *The Adequacy of Future Electric Power Supply: Problems in Policy,* Technical Advisory Committee to the FPC on the Impact of Inadequate Electric Power Supply, p. 75, in press when cited in memorandum to the New York State Public Service Commission from the Commission's Office of Research, *Re: Are Utilities Goldplated?,* April 14, 1976.

h Testimony by Edward P. Kahn before the New Jersey State Board of Public Utility Commissioners, Docket #762.194 citing a Systems Control, Inc., report to the California Energy Commission, p. D2 of Kahn's testimony.

All others: Ref. 34, p. 119.

The studies discussed so far are examples of studies that assume a static planning process. These efforts seek to define the social costs of having inadequate generating capacity. As shown in the discussions of Telson, Shipley et al., and Kaufman's works, the ultimate goal of these studies is also to estimate the costs of providing alternative levels of system reliability and to provide a basis for determining the optimal level. Thus, these types of studies could be used to establish targets for the amount of generating reserve to be planned for by the utility.

Another class of studies receiving attention recently addresses the economic issues allied with generating capacity expansion planning taking into consideration the dynamic characteristics of the utility planning process. These studies may use the target reliability levels established in the static planning process studies as a point of departure from which to assess the social costs and benefits associated with a matrix of alternative expansion plans and growth scenarios. Each of the three studies published to date conclude that the cost of planning and building too little capacity is greater than building too much capacity.[34-36]

Since these studies derive from the static planning process investigations, it is not likely that their results could be considered any more definitive than the results of the studies upon which they are based. Although a detailed and critical review of the dynamic planning process studies is beyond the scope of this current effort, such an analysis in the future might prove useful in defining or resolving DOE policy issues associated with utility reliability.

3.9 DOE, DIVISION OF ELECTRIC ENERGY SYSTEMS, ONGOING RESEARCH[37]

In December, 1976, the Division of Electric Energy Systems (DOE/EES) issued a request for proposals (RFP) for research in the area of "system effectiveness" analysis. The term effectiveness is used by DOE/EES to describe the overall attributes of a large-scale electric energy system in an attempt to view that system in terms of its cost, availability, performance, and worth.

The RFP and subsequent contracts were initiated in recognition that the effectiveness analysis, as in use today, involves sequential evaluations of cost, availability, performance, and worth of alternative system rationalizazations. The present approach fails to deal with the fact that these system attributes are not independent and therefore must be coupled to achieve the proper evaluation of the system.

The RFP goes on to indicate several deficiencies in earlier works, notably:

1. The lack of a consistent methodology for quantifying customer class tolerances to system availability and performance,

2. The indirect and unrealistic approach of present methods as well as their limited scope and remote level of abstraction, and

3. The fact that no general theory exists for defining a meaningful measure of the worth of availability as viewed by the customer.

The Division of Electric Energy Systems is seeking to resolve these deficiencies and to develop a framework of sound theoretical concepts upon which a theory of system effectiveness analysis might be developed. The objective of the program is to provide the utility industry with analytic tools that it may need in the future to assess their own level of effectiveness -- a future in which the utility may be required to assess the worth of a given system design or be required to provide different levels of service reliability to meet the needs of different customer classes.

The total program budget is in excess of $1.8 million with performance periods that began in fiscal year 1978 and are of two to three years duration. Five prime contracts and two subcontracts have been let. The five major contracts are with Systems Control, Inc., (3 yr, $542K), SRI International (1-1/2 yr, $175K), University of California, Berkeley (3 yr, $300K), ECON, Inc., (2 yr, $416K), and Texas A&M Research Foundation (2 yr, $480K).

The overall system effectiveness program objectives are clear; however, it is much too early in the performance period of the individual contracts to make an adequate evaluation and analysis of their approach and anticipated results.

3.10 ELECTRIC POWER RESEARCH INSTITUTE, ONGOING RESEARCH[38]

The Electric Power Research Institute (EPRI) has recently requested proposals and is now negotiating two contracts for the development of a methodology to assess the value of electric utility reliability to consumers. Each of these efforts would take different approaches toward quantifying that value.

One proposal by National Economic Research Associates (NERA) of New York suggests the development of a theoretical demand equation for electric reliability in each of the following sectors: industrial, commercial, residential, and transportation. Because the contract has not yet been signed, no additional information regarding NERA's proposed approach is available. A five-month performance period was proposed for this study, so EPRI results may not be available for six months to a year after the contract work begins.

The second approach was proposed by Resource Planning Associates (RPA) of Cambridge, Massachusetts. RPA proposes a survey approach similar to Ontario Hydro's. RPA's proposed one-year effort would begin with a review of Hydro's survey activities and, according to EPRI, hope to refine the questionnaires and procedures and extend the SICs covered in Hydro's earlier work. Results are not expected to be available for at least 18 months. Even then, it is not known to what extent actual survey data will be available.

It is unfortunate from the point of view of our effort that EPRI's results will not be available earlier. NERA has a long history in electric utility economic studies and their approach and results could prove useful. Likewise, RPA's survey results could provide a very good U.S. benchmark of industrial and commercial customer losses that might be correlated with Ontario Hydro's survey results. These efforts will be closely monitored so that their results can be further reviewed and, if useful, incorporated into our effort as early as possible.

3.11 THEORETICAL ECONOMIC MODELS

Each of the studies previously reviewed have relied on costs estimated by an external appraiser or the subjective valuations of customers to hypothetical situations as measures of the value of electric service reliability. This section discusses how customer preferences for electrical service, as revealed in the marketplace, might be used to measure the value of service reliability. First, general concepts of the classical "Marshallian" welfare approach are reviewed. These general concepts are then expanded in the discussion of a consumer welfare model that includes components of possible trade interruptions (reliability). Empirical work necessary to test and implement any welfare model of reliability is very limited. Some preliminary work that uses a welfare model and contains reliability assumptions is commented upon.

3.11.1 General Welfare Model for Reliability Analysis

Although a theoretical welfare model of trade with possible interruptions is not known to have been developed for applications that estimate the consumer's value of electrical service reliability, Tolley and Wilman[39] have used such a model to analyze the costs of oil embargoes. By analogy, an oil embargo is similar to an interruption in electrical services. Tolley and Wilman determine a loss function for supply interruptions and show how society sets its level of consumption and production to maximize social welfare. A similar use of economic welfare theory has frequently been used to analyze questions of peak load pricing[40,41,42] and mechanisms for sharing the costs of reliability.[43]

Common to the works cited above is the postulation of a social welfare function for measuring the costs and benefits of a policy or market change to consumer well being. "Welfare" as used in economic theory takes on a specialized meaning, much narrower than its significance in everyday usage. An economic welfare function is a way of describing an individual's (or an aggregation of individuals') preferences between various real or hypothetical alternatives. It does not measure the <u>intrinsic</u> value of choices by some normative standard; it measures the <u>relative</u> value of certain consumption sets, or bundles, in pecuniary terms.

Applied welfare analysis normally strives to quantify consumer gains or losses through the use of consumer surplus. In its simplest terms, consumer surplus is value minus cost. It measures the difference between what a consumer is willing to pay for a certain amount of a good and the price he actually must pay. Consumer surplus measurements are derived from well-known conditions for consumer utility maximization.[44]

An important obstacle to the use of the consumer surplus, as derived by Marshall, is that a constant marginal utility of income is assumed. Critics of Marshallian consumer surplus point out that as the price of a good decreases, all other things being equal, the consumer's real purchasing power from income increases. However, in applied welfare analyses, it is generally assumed that the good in question comprises a small enough portion of the consumer's budget so that moderate price changes will not substantially alter the consumer's real purchasing power.

A long-run demand schedule, $\ell(q)$, is shown in Fig. 3.7. Each point on the demand curve represents incremental value to the consumer for the last unit of goods purchased. Given a uniform price, P_o, the consumer will purchase q_o amount of goods. At this equilibrium demand point, the last unit purchased has a marginal value to the consumer that is just equal to the price. Hence, for the final, or marginal unit purchased, the consumer derives no benefits for which he does not pay -- he derives no "surplus" benefits. But for all incremental units of good preceding q_o, the marginal utilities are shown by the demand curve to be of greater value to the consumer. With the purchase of q_o units at uniform price P_o, the consumer derives some incremental surplus benefit from each unit preceding q_o. The incremental consumer surplus for unit q_1 is given by the difference between the unit price that the customer would be willing to pay at q_1 and the uniform price actually paid at equilibrium consumption q_o, i.e., $P_1 - P_o$. Total consumer surplus is the integral under the demand curve from zero to q_o units, less the customer's total cost for the purchase q_o units of good, or

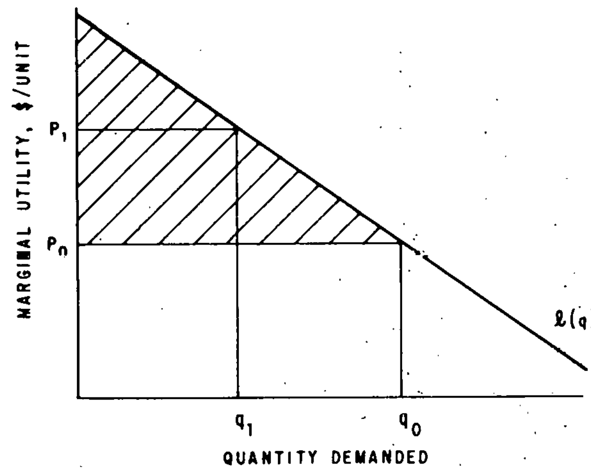

Fig. 3.7. Long-Run Demand Schedule

$$\text{Consumer Surplus} = \text{Total Utility} - \text{Total Costs},$$

$$\text{Consumer Surplus} = \int_0^{q_o} \left\{ \ell(q) - P_o \right\} dq,$$

$$\text{Consumer Surplus} = \int_0^{q_o} \ell(q)\, dq - P_o q_o \quad (3.15)$$

where:

$\ell(q)$ = long-run demand schedule
q_o = equilibrium demand, and
P_o = equilibrium unit price.

Equation 3.15 gives the consumer surplus for a single consumer. Aggregating across individual consumers poses some theoretical problems but, in principle, the total level of consumer surplus for the market can be developed by summing individual surpluses.

A customer's welfare benefits from the provision of electrical energy can be measured by the level of consumer surplus. Under perfect reliability, with no threat of supply interruption, the welfare function is equivalent to consumer surplus, or

$$W(q_o) = \int_0^{q_o} \ell(q)\,dq - P_o q_o \qquad (3.16)$$

where:

$W(q_o)$ = Consumer welfare with no threat of interruptions.

Eq. 3.16 represents the consumer welfare function with perfect supply reliability. In reality, long-term demand is influenced by unreliablity of supply. More precisely, the demand schedule, and thus consumer welfare is a function of reliability. In the model put forth by Tolley and Wilman[39] the treatment of possible oil embargoes accounts for supply reliability in terms of the probability of an embargo (supply interruption) occurring using short-run and long-run consumer demand functions. Some form of this model might also be used in a theoretical treatment of electrical service reliability if the probability of being without power due to a service interruption can be compared with the probability of an oil embargo.

There are difficulties in drawing a complete analogy between electrical supply unreliability and the Tolley and Wilman treatment of oil embargoes. In general, Tolley and Wilman calculate an optimal pricing strategy for a commodity which has historically been characterized by perfect supply reliability but which has recently been embargoed and for which there remains some probability of future embargoes. They do so by calculating consumer welfare under the threat of supply interruption. Estimating the consumer's value of electrical service reliability by any similar theoretical economic model would require the calculation of consumer welfare under varying levels of electrical supply reliability. Empirical evidence needed to estimate customer demand functions at different levels of reliability are not available in the economic literature.

3.11.2 Applications

Optimal pricing strategy is one area of investigation that may employ an economic model approach. Although the theoretical literature contains numerous examples of utility pricing schemes that maximize welfare functions, two recent papers stand out for their unusual implications. Crew and Kleindorfer[42] employ a producers' and consumers' welfare model to analyze the effects of alternative pricing strategies for peak and off-peak power when reliability is not perfect. They show that when perfect reliability is not assumed, multiple pricing optimality can occur due to the nature of the welfare function. They provide a framework for relating the optimal choice of reliability levels to the cost of rationing excess demand. Wenders[43] uses the welfare maximizing approach to show that off-peak customers should bear a portion of the system capacity cost because that capacity contributes to their reliability even in off-peak hours. This conclusion is, of course, at odds with the traditional conclusion that peak load customers should bear the entire capital cost of the capacity needed for peak load.

Although these and other studies can reach facile conclusions about pricing schemes that optimize the abstract welfare functions, the lack of empirical work on electricity demand functions that depend on reliability have limited the application of a general welfare model to calculating actual consumer value of electrical service as a function of reliability. In order to determine this relationship, it is necessary to calculate the change in consumer welfare between various levels of reliability. These calculations are not possible at this time because the functional dependence of long- and short-run demand schedules with respect to reliability are not known. Thus, although it may be possible to estimate long- and short-run demand for an existing level of reliability, data are not available from which to determine how demands would change in response to shifts in reliability. There may be an appropriate set of approximations and assumptions that would enable the model used by Tolley and Wilman to be applied in estimating the value of electrical service reliability using existing empirical data. The development and justification of that set of assumptions would require further development of the model and its theoretical basis as applied to electrical service reliability.

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4 CUSTOMER CHARACTERISTICS AND COMPONENTS OF THE VALUE OF RELIABILITY

Each individual customer has a unique set of electric energy requirements and level of incurred losses resulting from an interruption of service. These will vary widely within any attempted aggregation because a wide variability is present even among customers engaged in nearly identical activities. A customer's value of reliable electric power is dependent upon his service requirements and perceived interruption losses. These, in turn, are functions of a number of such independent factors as equipment or process design, availability of emergency back-up generation, ambient weather conditions, time of day or year and geographic location.

As pointed out in the previous section, many of the earlier attempts at quantifying the customer's value of electric reliability relied upon easily obtainable surrogate social indicators like gross regional or national product or wages and salaries. More recent work seeks to quantify less aggregate customer losses through the use of customer surveys. Although a more disaggregate quantification of customer losses is far superior to the use of a single "social index," problems associated with the generalization of these data and their transferability to demographic areas outside the survey region exist due to the special mix of customers in each service area and unique local economic conditions.

Nevertheless, it is not practical from a national policy evaluation viewpoint to attempt to quantify the characteristics of all individual customers and service areas. Nor is it sufficient, because of the diversity in service areas and customer mixes, to use the broad indices that have been used in the past. The most practical approach is to classify customers into a manageable number of groups broadly defined by their general electricity-use characteristics and values of electric service reliability. Such aggregations should facilitate both data acquisition and the modification of available existing data to conform to different customer mixes and service areas. Ideally, data modification should be accomplished using readily available regional or local economic and demographic information.

A reasonable disaggregation of customers is that being used by Ontario Hydro in their present customer survey work. These include the following six groups:

1. Large Manufacturers,
2. Small Manufacturers,
3. Commercial,
4. Institutional,
5. Agricultural, and
6. Residential (Urban and Rural).

4.1 CUSTOMER CHARACTERISTICS

The electricity use characteristics of large and small manufacturers (collectively referred to as industrial customers) are similar. Industrial customers normally have a relatively large demand (kilowatts) for electric power that remains quite stable from day to day or season to season. In general, larger industrial customers, with more continual production activities, have the most uniform demand for electric energy. Smaller customers who may run only two shifts per day with no weekend production have lower demands during evenings and weekends. However, these smaller customers exhibit a fairly constant demand during production hours.

Industrial electricity use can be broadly segregated into four functions: electric drives, electrolytic processes, direct heat, and other uses like electric controls, space conditioning, and lighting. The approximate annual percentages of total U.S. industrial electricity consumption used for each of these purposes are shown in Table 4.1. About 1% of all industrial electricity consumption derives from onsite generation by the customer.

Table 4.1. Functional Uses of Industrial Electricity Consumption

Function	Percent of Total
Direct Drives	80
Electrolytic Processes	12
Direct Heat	5
Other	3
Total	100

Source: *Patterns of Energy Consumption in the United States*, Stanford Research Institute, prepared for the Office of Science and Technology, Executive Office of the President, Washington, D.C., p. 68 (Jan. 1972).

Over 660 billion kilowatt-hours of electrical energy was purchased by industrial consumers in 1974. This figure accounts for 39% of all electrical energy sales to customers in that year.[2] The market share of electrical energy consumption by industry has declined slightly over the past two decades, despite its growth through time.

Because of the very large number of different products and processes used in industry, it is not possible to generalize about the power and energy levels of major equipment and process steps. At best, those industrial processes that consume unusually large amounts of electrical energy might be catalogued. However, because the value of electrical supply is less dependent upon the magnitude than it is upon the existence of the supply, the catalogue would have little significance. A comparison of the electrical energy requirements of U.S. manufacturing groups by 2-digit standard industrial classification (SIC) is shown in Table 4.2 for 1974 along with the value added by manufacture during that same year. As shown in the table, five of the six largest consumers of electrical energy (SICs 33, 28, 26, 20, and 32 and 29) have ratios of value added to electrical consumption that are less than the national average. Thus, although value added is only an index of of possible power interruption losses, it would seem to indicate that industry losses resulting from power interruptions may not be proportional to the <u>magnitude</u> of electric energy demand, and thus it may not be appropriate to identify large electric energy consuming processes.

Commercial and institutional demand curves are relatively high but constant during the daylight hours of the normal business day and fall off during the nighttime hours. Evening demand may fall off gradually due to the accommodation of evening shopping hours in many retail outlets. These classes of customers also show seasonal variations as a result of space conditioning and seasonal differences in lighting, which constitute their major energy requirements.

Several types of institutional customers perform fairly low electricity demand functions that may be critical to the maintenance of social order. It is not difficult to imagine such critical needs in hospitals, police and fire communications, prisons, or community water departments supplying high-rise office or apartment buildings.

Table 4.2. Electricity Consumption and Value Added by Manufacture by Major Industry Groups -- 1974

SIC	Industry Group	(1) 10^6 kWh Purchased	(2) 10^6 kWh Generated	(3) 10^6 \$ Value Added	(3) / (1) + (2)
20	Food and Kindred Products	36,879	2,657	44,769	1.13
21	Tobacco Products	1,028	-	3,217	3.13
22	Textile Mill Products	26,908	375	13,169	.48
23	Apparel (excluding Textiles)	6,357	-	14,943	2.35
24	Lumber and Wood Products	14,791	500	11,534	.75
25	Furniture and Fixtures	4,064	56	6,983	1.69
26	Paper and Allied Products	40,870	27,383	19,096	.28
27	Printing and Publishing	8,993	-	23,610	2.63
28	Chemicals and Allied Products	124,168	18,711	44,432	.31
29	Petroleum and Coal Products	27,340	4,475	9,951	.31
30	Rubber and Misc. Plastics	19,039	651	14,826	.75
31	Leather, Leather Products	1,509	15	3,120	2.05
32	Stone, Clay, Glass Products	28,856	600	14,600	.50
33	Primary Metals	163,319	22,385	37,297	.20
34	Fabricated Metal Products	25,199	105	35,221	1.39
35	Machinery (excluding electric)	26,062	355	52,495	1.99
36	Electric and Electronic Equip.	24,658	171	36,902	1.49
37	Transportation Equip.	28,375	-	44,973	1.58
38	Instruments & Related Products	235	-	13,674	58.19
39	Misc. Manufacturing Industries	3,922	-	7,667	1.95
	Totals:	612,572	78,439	452,479	0.65

Sources: *Annual Survey of Manufacturers 1974 - Fuels and Electric Energy Consumed*, Table 6
Statistical Abstracts of the United States, 1977, Table 1376

Approximately 30% of all electrical generation is consumed by commercial and institutional customers. This proportion has increased somewhat since 1960, nearly balancing the slight relative decline in industrial consumption.[3]

Residential and farm customers show even greater temporal variability in their demand for electrical power than do commercial and institutional customers. Demand, particularly by residential customers, is very strongly dependent upon seasonal weather variations and also exhibits very pronounced daily peak demands during the early morning and early evening.

Figure 4.1 shows the monthly-averaged electrical energy use for two samples of single family homes in Madison, Wisconsin. The sample of homes with central air conditioning show electrical energy demands during the peak summer months that are about 80% greater than their fall/winter/spring averages. Summer demands by homes with no air conditioning, on the other hand, show summer peaks that are generally less than the winter peak and are comparable to the non-summer average demand. The effect of residential summer peaks on utility systems has become more pronounced in the past decade with the increased use of air conditioning.

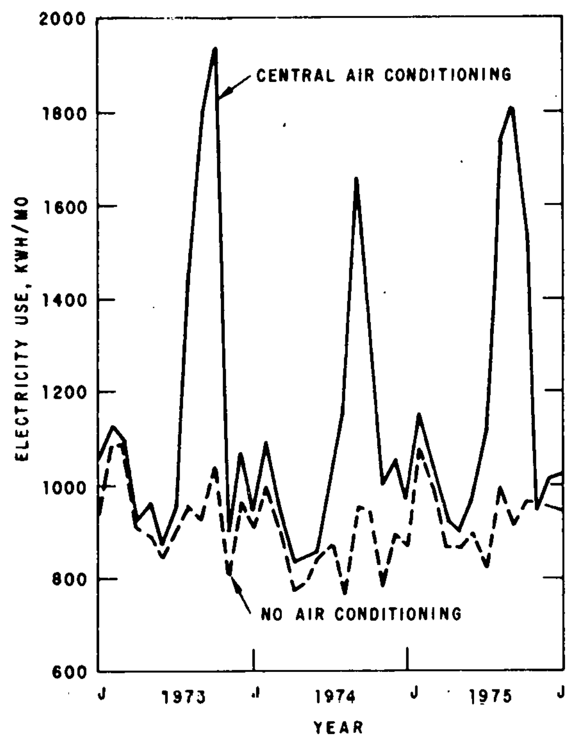

Fig. 4.1. Monthly-Averaged Residential Electrical Demand, Madison, Wisconsin, Housing Sample

Source: Mitchell, J.W., G.I. Venkataro, *Energy Use in a Sample of Homes in Madison, Wisconsin*, IES Report 72, Energy Systems and Policy Research Group, Institute for Environmental Studies, University of Wisconsin, Madison, p. 19 (Feb. 1977).

Daily load variations in the residential and farm sectors are primarily a result of domestic uses of cooking equipment, hot water, and lighting. During periods of food preparation, refrigerators are usually being opened and closed more frequently and thus are required to run more frequently. Also, indoor food preparation during the summer adds not only its own demand, but a secondary demand due to the added heat that is removed by air conditioning.

Nationwide, about 34% of all electrical generation is consumed by the residential and farm sectors. This percentage has also increased slightly from 1960 when residential sales accounted for nearly 29% of the electric energy consumed in the United States.[4]

4.2 CUSTOMER VALUES

In order to estimate the overall values of reliability, it is desirable to aggregate customers who not only have similar use characteristics, but who also have similar values of reliability and a similar willingness and ability to pay for any given level of service reliability.

A customer's ability to pay for alternative reliability levels is dependent upon the availability of economic resources in comparison to the sum of all other financial requirements. The willingness to pay is a function of the alternatives available to the customer and his expected return. That is, the rational customer would not be expected to pay the utility to provide added reliability if it does not benefit him to a corresponding extent.* These customers would also not be expected to pay for utility provided reliability if the same level of service can be obtained at less cost by constructing in-house emergency back-up generation or executing some other option that may be less costly.

The following discussion of the customer's value of reliability assumes that all customers who are willing to pay for an alternative level of reliability also have sufficient financial resources to enable them to do so. If cost of service is an increasing function of service reliability, the assumption then is surely valid for decreases in reliability. For increases in reliability, the assumption is not likely to be violated within small variations of a few percent increase in the customer's electricity costs.

*This strict statement that assumes marginal benefits to be greater than or equal to marginal costs may not tell the whole story in that some customers may be willing to pay a slight premium for more reliable service as an insurance factor against uncertainty in their marginal cost/benefit analysis.

The value of electric service reliability to particular customers (or customer classes) is subject to their service requirements and perceived interruption losses (or costs) modified by the probability that a service interruption will occur. Clearly, a customer's value of reliability must be at least as great as the product of expected economic losses caused by a service interruption and the probability of that interruption occurring, summed over all possible interruptions. However, the customer's value of reliability may be greater than this because of certain external or non-dollar costs that are incurred as a result of an interruption. R.B. Shipley et al. recognized such costs in their 1972 IEEE paper when they referred to the effects of power interruptions on customer comfort, convenience and safety.[5] But external costs may also include indirect customer costs such as the release of additional environmental pollutants due to inoperable pollution control devices.

Unfortunately, external costs are often difficult to quantify and thus it is difficult to assign a value to them. This valuation problem exists not only for the utility analyst, but for the customer as well. However, external costs may be the most important factor in the decision processes of some individuals. It is not usually possible for a customer to accurately perceive, or even to identify, the external costs associated with a level of service reliability that has not actually been experienced. This phenomenon is exemplified in the recent customer survey by Consumers Power Company.[6] When two groups of customers were asked to rate the seriousness of various durations of power outage, the group of customers who had recently experienced those outages uniformly rated each duration category as less serious than did the group of customers who had not experienced any recent power outage. This survey was only of residential customers, and it should not be inferred that all customer classes, or even residential customers in all service areas, will tend to overestimate the seriousness of an outage if they have not recently experienced one.

It is important to mention that although it is difficult for the customer to value external costs (or benefits), he does so for nearly every product that is purchased. The evaluation of external costs and benefits may not be very visible in the purchase of small items, but for large items like an automobile, external factors such as the vehicle manufacturer and dealer reputation become important considerations.

A customer's internal costs (direct dollar costs) and external costs due to an interruption in electrical service will vary extensively and will depend upon numerous independent factors. Even two customers subjected to identical power interruptions and incurring identical dollar losses, may be exposed to divergent external costs. And, in accordance with the individual customer's tolerance to those costs, each may value more reliable service by differing amounts.

Figure 4.2 is one example of possible customer interruption costs and values of reliability drawn from an infinite number of possible sets. Actual relative costs and values may vary significantly from those shown. In the base plane of the figure, customer regimes in internal/external cost space are shown for the six customer groups whose use characteristics were previously described. The fact that these regimes are shown as a range of internal and external costs is intended to portray the existence of uncertainty in the estimation of these costs. The relative positioning, size, and shape of these regimes, as well as scales assigned to each of the axes will vary according to geographic area, intra-group customer mix, season, aggregate

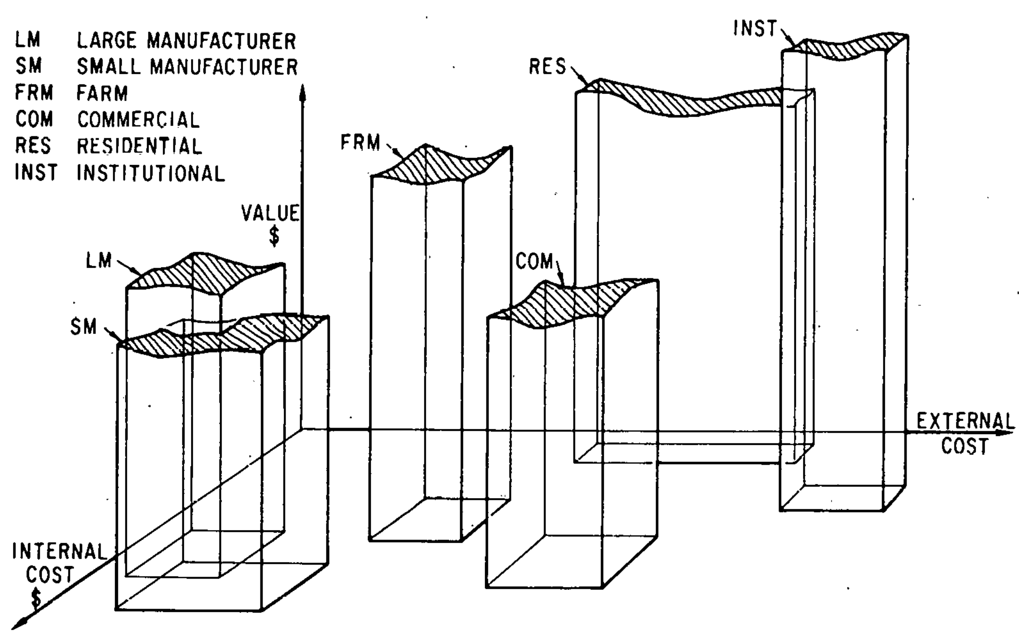

Fig. 4.2. Possible Set of Customer Interruption Costs and Values of Electric Service Reliability

outage characteristics (frequency, duration, etc.), and other factors. Synergistic social effects in New York City may well add greater unit external costs to an extended outage than would be experienced in Springfield, Illinois, for example.

The vertical dimension of Fig. 4.2 represent the value that each customer group might assign to, and be willing to pay for, an increment of service reliability. These are also subject to a significant amount of uncertainty and variability as indicated by the irregular upper limit of each bar. Each customers group's value is a function of its aggregate tolerance toward both the internal and external costs incurred as a result of the frequency and duration of power interruptions that define the cost regimes in the base plane of the figure. Again, it is only the concept of the interrelationship between internal costs, external costs, and value that is portrayed in Fig. 4.2. Actual relative positioning and magnitudes may differ significantly.

As is readily apparent, the key constraints to assigning values to customer's electric service reliability are the great variability and large uncertainty associated with the customer's operating environment and interruption costs. Much of the ongoing work, particularly by Ontario Hydro (and perhaps EPRI) is seeking to narrow the bands of uncertainty in terms of the customer's internal costs. Additional data and a methodological procedure for comparing and transferring data to other service regions are lacking at this time. The work currently under way by EPRI and DOE/EES may be directed toward making advances in these deficient areas, although it is too early within the performance periods of these studies to make detailed evaluations as to the contributions they may make.

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5 OPTIONS FOR ALTERING CUSTOMER SERVICE RELIABILITY

Service reliability is defined as the level of continuity and quality of electric supply to an electric utility customer's end-use device. Numerous technical and operational options are presently or may potentially be available to alter customer service reliability relative to its existing level. Each particular option may be classfied by whether it is utility or customer owned or selected and whether it is activated or initiated by the utility or customer during day-to-day operations. In the case of utility owned or initiated options, alterations in service reliability may affect only some or all customers in the utility's service region, a geographic subregion, certain customer classes, or even selected individual customers, depending upon the option selected by the utility. Customer owned or activated options, on the other hand, primarily affect the service reliability of individual customers. Large numbers of certain customer-operated options in any single service area, however, may also affect the service reliability of other customers, or even the entire service area.

Figure 5.1 classifies several generalized options for altering customer service reliability by customer or utility selection during the design or planning phase and by customer or utility activation during the operating phase. Decisions regarding customer selected and customer activated options (Class A) are made by the customer, largely independent of the utility's decision processes. Likewise, decisions regarding utility selected and utility activated options (Class D) are made by the utility, largely independent of the customer's decision processes. There is of course some level of influence between the customer and utility with respect to decisions regarding these options. For example, the customer will be influenced by his expectation of the quality and price of utility provided services; the utility will be affected through the regulatory process and its perception of customer requirements. These influences are less direct and less well defined than for the other classes of options.

Options selected by the customer and subsequently activated by the utility during the operational phase (Class C) are usually arranged under special contracts that specify the exact requirements. Contracts vary among utilities and within utilities as well, depending upon the frequency with

OPERATIONAL PHASE: ACTIVATED BY...	DESIGN PHASE: SELECTED BY...	
	THE CUSTOMER	THE UTILITY
THE CUSTOMER	Class A Options: 1. Supplemental Emergency Power Generation 2. In-House Generation With Utility Backup 3. Storage Devices 4. Voltage Regulators & "Uninterruptible" Supplies	Class B Options: 1. Customer Peak Demand Charge 2. Time-Of-Day Pricing 3. Voluntary Public Appeals
THE UTILITY	Class C Options: 1. Interruptible Service Contracts 2. Pulse-Controlled Devices 3. Special Supply Provisions	Class D Options: 1. Generation Reserves, Configuration, & Interties 2. Transmission Configuration & Design 3. Distribution Configuration, Design & Maintenance 4. Operational Procedures

Fig. 5.1. Generalized Options for Altering Customer Service Reliability

which certain options are employed, the level of service flexibility, and other factors. Nevertheless, for the selection of each Class C option, there is a large degree of customer-utility interaction or negotiation. Once selected, however, the utility generally controls its operation.

Class B options are those selected by the utility and activated by the customer during day-to-day operations. For the options listed in Fig. 5.1, customer-utility negotiations take place via the regulatory process through which the final rate formulas are determined. Once approved by the regulatory commission, it is the customer who determines his own pattern of electricity use during daily operations.

Within each of the four classes of options are several technologies or operational procedures that may be employed by the utility or its customers. Each of these is discussed in greater detail in the following sections.

5.1 CLASS A OPTIONS: CUSTOMER SELECTED/CUSTOMER ACTIVATED

Customer selected and activated options are typically housed on the customer's property and under his direct control. In general, this class of options is employed only to increase the customer's electrical service reliability. The term "customer" implies some level of electricity purchase from the utility. Thus, electricity consumers without any electrical connection to the utility grid -- those who consume only what they generate themselves with no reliance on the utility -- are excluded from consideration.

Customer selected and activated options vary over the entire spectrum of associated dependence on the utility, and include the following:

1. Supplemental emergency power generation,
2. In-house generation with utility backup,
3. Storage devices, and
4. Voltage regulators and "uninterruptible" supplies.

Supplemental emergency generation activated in the event of a utility supply failure is perhaps the most common option employed. Many industrial and commercial customers and even some residential customers have such back-up devices. Industrial and large commercial customers may use gas turbines or diesel generators; smaller emergency power generators are not capable of carrying all of the customer's normal load, but usually are sufficient to operate critical components such as process controls and lighting in industry, sump pumps and emergency lighting in commercial establishments, and residential lighting.

At the other end of the spectrum is nearly total in-house generation with reliance on the utility for electricity only when the in-house generation fails. This option is usually considered only by the largest industrial consumers who might consume hydrocarbon fuels and process wastes or even hydro-power to generate electricity. Cases also exist where the customer is capable of generating electricity in excess of his own requirements. Often, this excess generation is sold to other nearby customers or sold to the electric utility for use throughout their grid.

Energy storage devices may also be used by utility customers to increase their level of reliability. Because electrical energy cannot itself be stored, it has to be converted to some chemical, thermal, mechanical or electrochemical form for that purpose. Examples of some selected storage technologies and possible applications are included in Table 5.1. Thermal and electrochemical storage systems are in wide use by industrial, commercial, and residential customers. Chemical and mechanical storage systems have been used primarily but not extensively by industrial customers. Electrical services, when available, are used to "charge" the storage devices. During an interruption of electrical services, the stored energy may be used directly or reconverted to electricity. These storage options are generally connected in parallel to the normal service and can be employed by manual or automatic switching in the event of an interruption of utility services.

Some utility customers, such as those with computer facilities, require not only a continuous but also a high quality supply of electrical energy. Quality refers to the nearness of delivered voltage and current to system specifications. Under normal operations utility-provided voltage and current frequency vary somewhat with respect to delivery specifications (120 V, 240 V, etc., and 60 Hz). Occasional switching on the customer side of the final step-down transformer and other day-to-day activities by customers on the same feeder line may also cause short-term voltage and current fluctuations. Also, during peak demand periods, the utility may selectively reduce its delivery voltage to reduce some of its load.

Customers who require a higher quality of service than that provided by the utility may install either voltage regulators or "uninterruptible"

Table 5.1. Examples of Current and Potential Storage Technologies

Type	Storage Medium	Applications
Chemical	Hydrogen	Combustion
Thermal	Water; Crushed Rock	Process & Domestic Hot Water; Space Conditioning
Mechanical	Flywheels	Mechanical Drives; Electricity Generation
Electrochemical	Batteries	Emergency Lighting; Process Controls; Communications

supplies depending upon the tolerances of their equipment. Customers requiring a very high quality electrial service might install what is termed uninterruptible power supplies. Two types of systems are in use today, and both incorporate a storage device as a buffer between the utility's service and the customer's equipment. One type uses a motor-flywheel-generator arrangement. The motor is run directly by the utility-provided electricity and imparts its shaft energy to the flywheel where it is stored as kinetic energy of rotation. This energy is subsequently used to turn the generator to produce electrical power for the customer's equipment. With this arrangement, the generator and equipment are filtered from utility supply variations and the customer's equipment can be protected against a complete interruption of utility supply. The length of the interruption that it can be protected against is a function of the surplus energy stored in the flywheel, which is dependent upon the flywheel's mass and rotational velocity.

The second type of uninterruptible power supply utilizes a "battery float" between the utility supply and the customer's equipment. Utility provided alternating current (ac) is converted to direct current (dc) and continuously charges a bank of batteries. Energy is also continuously removed from the battery bank as dc and converted to ac for use by the customer's equipment. Thus, the equipment is never directly connected to the utility supply. Variations in utility service are completely filtered by the battery bank. This device may also sustain equipment operation for some time in the event of a complete electrical service interruption. The length of time over which equipment operation can be maintained depends upon the storage capacity of the battery pack and power requirements of the customer's equipment. (A capacitor or capacitive circuit may replace the battery pack, but this option generally will not be able to provide power continuity for the extended periods of time possible with batteries.)

Customers who do not require a high degree of service reliability might install voltage regulators. In general, voltage regulators are variable-tap transformers that monitor their output voltage and automatically change taps to maintain that voltage within specified limits. A voltage control range of $\pm$ 10% is nominally accepted by U.S. electrical equipment manufacturers. This range is usually controlled in steps of $\pm$1%, $\pm$2% or $\pm$5% depending upon equipment tolerances.[1]

Two major disadvantages are associated with variable-tap voltage regulators. First, because the voltage corrections are made incrementally rather than continuously, the customer's equipment may still see power transients caused by the tap switching operation. These transients can be somewhat reduced by the addition of an electronic filtering circuit between the voltage regulator output and the customer's equipment. The second major disadvantage of variable-tap regulators affects the electric utility. During periods when the utility initiates a systemwide voltage reduction to achieve some measure of load relief, a customer's voltage regulator begins to draw additional current, nullifying the load relief sought by the utility.

5.2 CLASS B OPTIONS: UTILITY SELECTED/CUSTOMER ACTIVATED

Utility selected-customer activated options for changing reliability include those that are characterized generally by voluntary actions to reduce demand during periods of overall high demand for electrical services, or simply to control their periodic maximum demand in general. These options may be implemented by the utility either through the rate structure or through public appeals during periods of severe capacity shortages. This class of options include:

1. Customer peak demand charge,
2. Time-of-day pricing, and
3. Voluntary public appeals.

The peak demand charge concept was first developed in the early 1890s in England by Hopkinson and Wright. The objective was to allocate at least some of the cost of providing sufficient capacity to meet the customers maximum demand equitably. The charge is proportional to a customer's maximum demand (kilowatts) during a specified period (usually one month) and serves to prevent customers from imposing unnecessarily high kilowatt demands on the utility system.[2]

A more recent concept, that of time-of-day pricing, is presently being studied by several U.S. utilities and has been implemented by other utilities for some industrial customers. This option seeks to reallocate a portion of the aggregate customer demand occurring during daily system peak periods to those daily periods when system demand is lower by pricing peak-period energy consumption (kilowatt-hours) at a higher rate.

Both the peak demand charge and time-of-day pricing can be viewed in two ways. First, these rate structures are closer approximations to incremental pricing of electrical services than those provided by the various average cost of service rate structures. This aspect, in and of itself, does not affect service reliability. Second, because of the higher charge imposed due to periodic peak demand or system peak period energy consumption, some electric utility customers will choose to demand fewer kilowatts during the system's peak period. Thus, these pricing methods can be viewed as a means of peak load management that has the effect of increasing system reliability during the peak periods. Assuming that the same amount of energy (kWh) will be consumed with or without exercising one of these options and that no system design changes are made, the increases in system reliability during the peak periods will be only partially offset by decreases in system reliability during off-peak periods resulting from additional off-peak demand.

A third option for increasing system reliability during peak periods is through voluntary appeals by the utility to its customers through a public medium such as radio or television. This option is usually exercised by electric utilities during periods of critical on-line capacity shortages. As some customers reduce demand, the operating capacity reserve margin increases, the probability of loss of load decreases, and system failure becomes less likely.

In each of these cases, whether customer peak-period demand is reduced by price incentive or penalty, or whether customer demand reduction is strictly voluntary, it is always the customer's choice to perform a specific action -- be that to reduce or to maintain a certain demand level. It is emphasized that the customer who <u>chooses</u> to reduce demand because of price incentives or public appeals is not considered to have experienced a loss of service, since a choice could equally well have been made to continue or even to increase demand. Individual choices to reduce demand, however, do benefit those customers who choose to continue their requirement for electrical service, by effecting an increase in <u>system</u> reliability. Thus, in one sense, it is possible for customers to benefit from a partial reduction in their demand, which has the effect of increasing the reliability of the portion of services they elect to continue demanding from the utility system. Certainly, it would be very difficult to quantify the extent to which this possible feedback compensates for the customer's choice to reduce a portion of his demand.

5.3 CLASS C OPTIONS: CUSTOMER SELECTED/UTILITY ACTIVATED

This class of options affecting the customer's electrical service reliability covers special contractual arrangements between the customer and the utility. Specifically, these are:

1. Interruptible service contracts,
2. Pulse-controlled devices, and
3. Special supply provisions.

Interruptible service contracts and the use of pulse-controlled devices generally decrease the affected customer's level of service reliability. Like the Class B options, however, the execution of these two options tends to provide additional operating flexibility to the utility and tends to increase system reliability during peak demand periods.

Interruptible service contracts are usually available only to large industrial customers. In consideration of a lower rate schedule, the utility reserves the right to interrupt services to the customer in accordance with provisions specified in the contract. Contract provisions might specify the maximum frequency, duration, and total normal energy requirements that may be interrupted in a yearly period as well as the amount of advance notice required to be given by the utility. Depending upon the physical arrangements, the utility may actually disconnect the customer's load or the customer may be contractually bound to disconnect his load within a specified time limit. In the latter case, the contract may also specify severe cost penalties for failure to disconnect within that time limit.[3] In 1970 about 32% of U.S. utilities offered interruptible service contracts to their customers.[4]

Pulse-controlled devices are essentially electronically operated switches selectively controlled by means of a coded pulse riding on the nominal 60Hz current provided to the customer. Because it is not possible for the control pulse to propagate through transformers, it is necessary to initiate the signal on the customer side of the final step-down transformer or install a filter circuit to bypass the pulse signal around the transformer.

A utility operator might control remote pulse generation devices located at the customer's side of the transformers via microwave communication equipment.[5] Since the control switch can be coded to recognize and respond to only certain signals, the utility can interrupt service to selected consumer processes or appliances, and may even restrict the interruption to certain geographic areas or customer classes. Several U.S. utilities are presently experimenting with these devices applied to residential hot water heaters and air conditioners.

Individual customers such as hospitals, communication facilities and computer facilities, who require a higher level of service reliability than normally provided by the utilty, may contract for special supply provisions. These provisions would generally be specially designed or arranged subtransmission and distribution facilities. Specifically, a customer may desire feeders that can be energized by more than one substation, the installation of an underground feeder, or a high degree of distribution system sectionalizing and automation for protection against substation or distribution failures.

5.4 CLASS D OPTIONS: UTILITY SELECTED/UTILITY ACTIVATED

The utility has perhaps the most varied selection of options available for altering their customer level of service reliability. These encompass options related to the:

1. Generation subsystem,
2. Transmission subsystem,
3. Distribution subsystem, and
4. General operational procedures.

As previously noted, options that alter the reliability of the generation subsystem potentially affect all of the utility's customers. Changes in the level of reliability of the transmission subsystem may, under certain conditions, alter the level of reliability to fewer customers, and changes in the distribution subsystem will affect even a smaller number of the utility's customers.

Numerous options are available for changing generation subsystem reliability. These include generating capacity reserve, interties with other utilities, overall generation fuel and unit capacity mixes, multiple fuel capability at individual stations, degree of decentralization of generating capacity, and the utility's scheduled maintenance procedures.

Generating capacity reserve is the most frequently referenced option in discussions regarding utility reliability because of the large capital investment needed to provide whatever reserve capacity is considered appropriate and the small fraction of time during the year that it is operated. Some amount of reserve capacity is necessary to cover uncertainties in the peak demand forecast, and to substitute for base and intermediate load capacity that may be forced out of operation due to unexpected causes, scheduled maintenance, or because of partial derating for environmental or other reasons. Clearly, the more reserve capacity available to a utility, the better protected it will be against unanticipated unit outages, extended maintenance schedules, or higher than expected peak demand.

A utility may also rely on interties with neighboring utilities to increase its level of generation reliability. Electricity purchased through interties (transmission lines connecting two or more utilities) may be under either a firm or emergency contract arrangement. Under a firm purchase contract the selling utility treats the purchasing utility just like another customer and provides electrical power upon demand. The firm purchase contract may specify limitations on one or both utilities. Under emergency intertie arrangements, utilities generally negotiate short-term sales and purchases of electrical power during periods of need. The selling utility provides power only if sufficient capacity is available and is under no obligation to do so. Hence, by either a firm or emergency intertie with neighboring service areas, a utility can increase its own reliability. This expedient often serves as an economical alternative to the construction of additional reserve and is usually a favorable arrangement for all utilities involved.

Another means of altering the utility's generation reliability is by varying degrees of generation fuel mixture. The more diversified a utility's fuel mix, the less dependent that utility is upon interruptions in the supply of any single fuel type. The effect of fuel diversification was very evident during the recent national coal strike. Those utilities strongly dependent on coal found themselves short of sufficient fuel to meet their customer's demand. Emergency purchases and public appeals to curtail demand were the only measures that enabled many utilities to survive the critical fuel shortage. Diversification of fuels, however, does subject the utility to the greater probability that any one of their fuel types will be interrupted.

Along these same lines, multiple fuel burning capabilities in a utility's generating facilities also serve to increase their reliability. Many utility boilers can be designed for relatively quick conversion to either coal, oil, or gas. The ability to burn any of these fuels in the same boiler guards against a supply interruption of any one of the fuels.

Regardless of the number of fuels that can be burned in any generating facility, generation reliability can be enhanced by larger onsite storage of fuels. This strategy is particularly true for coal and oil burning facilities, since these fuels are relatively easy to store. It should be noted that many eastern utilities had increased their coal supplies from a 30- to 90-day supply in anticipation of the recent coal miners' strike. However, because of the extreme length of the miners' walkout, even the additional provisions were inadequate in many cases. On the other hand, Canadian utilities who import much of their coal from the United States, were not affected by the coal strike because it is normal practice for these companies to store up to 12 months' worth of coal supplies. This is a general practice because barge transportation via the Great Lakes is interrupted for most of the winter.

Because of their storage capabilities, supplies of fossil and nuclear fuels are relatively assured as compared to some renewable sources such as direct and indirect solar energy. These sources of energy, although inexhaustible are randomly intermittent. The relationship (if any) between solar-based energy source availability and a utility's load profile is largely unknown, but is being investigated at this time. Thus, the effect of solar-based generation either by small dispersed systems or large ground-based centralized electric power facilities is largely unknown. Also important with regard to transmission reliability are the effects of centralized versus decentralized power generation, either with solar or conventional fuels; this aspect is discussed later.

Another area of utility practices that may affect generation reliability is the utility's generation plant maintenance procedures. Generally, scheduled maintenance is performed during off-peak seasons to provide for the maximum availability of capacity during the seasonal peak periods. The degree to which a utility is able to perform all of its scheduled maintenance during the off-peak season will affect generation reliability. Time and capacity contingencies and the amount of power a utility is willing to purchase in order to perform off-peak season maintenance are important factors affecting reliability. Other contributing factors are the size and quality of the utility's maintenance force.

Transmission subsystem reliability is influenced mainly by the physical configuration of the utility's transmission network, its design specifications, and exposure conditions. A system's configuration determines the utility's ability to reroute electrical power to customers in the event of a fault in a line segment. The extent to which a utility has installed automated control and switching devices, as well as its level of backup equipment, will determine the rate at which the customer's power is restored given a transmission segment failure and an appropriate line configuration.

The majority of all transmission line failures is related to exposure, which refers to the length of line segment between two points and prevailing environmental and meteorological conditions. The shorter the line segment, the less likely it is that it will be adversely affected by severe environmental conditions. Decentralized energy systems located near load centers would be associated with shorter transmission lines than would larger centralized generation systems serving the same collection of load centers. Shorter lines offering less environmental exposure should therefore provide a higher level of reliability to the customer. But, reliability is also dependent upon system configuration and the extent to which generating capacity and load centers are interconnected. Interconnection requires additional transmission facilities, and these are subject to enviromental exposure and failure. Optimum system design depends on many varying factors for each utility and cannot be determined without consideration of existing and planned generating plants and demand center growth projections.

Since environmental exposure is the major cause of transmission line failures, the extent to which a utility "over-designs" its transmission facilities also affects customer reliability. Of major importance in transmission line design are the historic frequency distributions of high winds and ice storms. Future expectations of adverse weather conditions are based upon historic data and transmission lines are designed accordingly. Design criteria vary by utility but are usually expressed in terms of the structures' ability to withstand the maximum sustained wind velocity expected once per specified period, or some maximum ice loading if the utility experiences occasional ice storms.

Underground transmission facilities, though not the most efficient, are an obvious means of eliminating many adverse environmental conditions to which overhead lines are exposed. They are much more costly, can carry less power, and require longer repair times in failure modes such as flooding, short circuiting, and others.

Besides the utility's physical system and the level of reliability it provides, some of the utility's operating procedures will also influence the reliability of service experienced by various groups of customers. Most notable are the utility's priority sequence for loading shedding and its operating flexibility for delaying that action. Numerous measures are executed by a utility before it becomes necessary to shed load. Typically, a utility will call for emergency power purchases from neighboring utilities, disconnect its interruptible customers, and make public appeals for voluntary cutbacks before load is dropped. These options were discussed previously. The utility is also a large consumer of its own electricity, and thus has the capability of curtailing a portion of its own load before interrupting its customer service.

Another longer ranged policy practiced by many utilities is to maintain its older generating units rather than retire and decommission them. These older units serve as additional reserve capacity although they are typically not as quick starting as newer gas turbine or diesel generators.

In the event that load shedding becomes necessary, the customer's reliability can be affected by the utility's policy toward customer interruptions. Typically, voltage reductions or "brown-outs" are implemented first. A utility can usually curtail up to a maximum of 5% of its load by reducing voltage by 8%. As noted previously, some customers will need to curtail their production at substantially less than the maximum voltage reduction. When voltage reductions are not sufficient, customer disconnection becomes necessary. This process is usually initiated at the substation level with some utilities capable of shedding increments of 15-20 MW. Other utilities can shed load only in larger increments. Load is shed typically by geographic area, and thus the utility is capable of distinguishing customer classifications only to the extent that they may be concentrated geographically. In many cases, however, a mix of customer classes exists in any specified area. Exceptions to this generalization are large industrial customers served directly by the utility via a separate substation and large areas of residential customers.

Utilities have formulated plans for load shedding priorities as urged by the Federal Power Commission in Order 445, January, 1972.[6] Normally, predominantly residential areas are the first to be dropped when load shedding becomes necessary. The extent to which existing load shedding priorities are equitable to all customer classes is a major question presently being asked by many utilities and regulatory bodies.

5.5 COSTS OF RELIABILITY-ALTERING OPTIONS

Some cost is associated with each of the options that is available for altering customer service reliability. The costs of the various options may be borne directly by the utility or by the customer either directly or through the utility's rates. The cost relationships between reliability and equipment options such as emergency power generators, special supply provisions and generation, transmission, and distribution subsystem design are relatively easy to quantify for a particular customer or utility. A generic estimate of these relationships, on the other hand, is complicated by the wide diversity of customer requirements and utility system designs and practices.

The class of options selected by the utility and activated by the customer (Class B) is strictly voluntary on the customer's part. Very little quantitative understanding exists with respect to the effect of a customer demand charge or time-of-day pricing on the system's load pattern and, thus, on the system's level of reliability. No U.S. utility has yet initiated wide scale time-of-day pricing although some are experimenting with the concept. Likewise, the amount of load relief available through public appeals for voluntary cutbacks can only be estimated, based upon a particular utility's prior experiences and will vary in accordance with existing weather and other conditions.

Nevertheless, the costs associated with all of the options available for altering customer service reliability are intimately related to its value to customers and their willingness to pay for it at a specified level. Some options may be available only to some customers and some utilities. Thus, in estimating a particular class' willingness to pay, it will be necessary to determine the cost of all options for which adequate quantitative data is available since the customer decisions will be based on the least-cost alternative that satisfies the customer's requirements.

5.6 OTHER CONSIDERATIONS

The options discussed in this section are those that directly affect the customer's level of electrical service reliability and hence only include the ones that provide electricity for customer use.

Other considerations enter into the customer's requirements and value of electrical service reliability, of which the most notable are options to use a different power source like natural gas for process heat, or steam for mechanical drives. Another possible option is a process designed for temporary or decreased (but continued) operation in the event of an electrical power failure. The extent to which these other types of options are available to customers affects their value of electric reliability because they tend to decrease their losses during an electrical power failure. These options have not been discussed in detail because they do not alter customer electrical service reliability, but do affect the ability to continue operations in spite of power interruption.

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6 POLICY ISSUES

Policy issues related to customer electrical service reliability have grown out of the recent and dynamic state of affairs experienced by the utilities, their customers, state and federal regulatory agencies, and federal technology R&D organizations, such as DOE. These issues are particularly complex because of the integrated nature of electricity use in nearly every day-to-day activity engaged in by American society and the large capital and fuel intensity present in U.S. electric utilities.

The current state of affairs is dominated by major concerns about all forms of future energy availability, environmental and socioeconomic effects of energy production and use, high unemployment, rising inflation, and a tight capital market. These and other influences have caused the various interest groups, or stakeholders, to question previously accepted methods of operation in an effort to relieve the strain that these factors have caused.

In many cases, the objectives of the various stakeholders are in conflict with each other and require compromise to achieve some viable action that will improve the present state of society. The question of electric utility system and customer service reliability management brings into view many such objectives that ultimately need to be formulated into a comprehensive action policy. The DOE Office of Technical Programs Evaluation under the Assistant Secretary for Policy and Evaluation seeks to define policy actions that will improve today's energy (and economic) situation in as equitable a fashion as possible by considering the objectives of all involved or interested parties, rather than those of a single entity.

6.1 PROFITABILITY AND RATE STRUCTURES

To formulate such policies with respect to electric utility system and customer service reliability, the major issues involved need to be defined. First, electric utilities are regulated monopolies and must seek approval from state and federal regulatory agencies for most matters related to capital expansion and customer rates. Because they are monopolies, the utility's charter requires the provision of electric power to its customers upon demand. This proviso has previously been interpreted as requiring the utility to provide as high a degree of reliability as reasonably possible to all of its customers. Many utilities are now finding it difficult to get approval for sufficient rates to continue to provide reliable service in the manner to which they are accustomed -- generally by a large generating reserve margin. A recent example is that of the Southern Company that provides electrical services to four southern states.[1] Because of its inability to gain approval for increased rates, Southern is allowing its capacity reserve to decline from 20 to 15% in an effort to keep pace with growing demand and their investors' expected rate of return. The decline in reserve capacity will surely affect Southern's reliability.

Most utilities are experiencing problems similar to those of Southern. The high cost associated with providing reliable electric service and the corresponding higher rates required from the utility's customers is one of the most important issues facing the utility industry. As a result of this issue, utilities and state regulatory agencies are questioning the conventional means by which a desired level of reliability is provided. Questions are being raised and new techniques sought in terms of electricity pricing mechanisms and transmission and distribution subsystem design to achieve reliability in a more cost-effective manner. Time-of-day pricing is also a popular issue that became of interest because of technological developments that make time-of-day metering possible. At variance are the relative benefits and costs associated with this pricing mechanism. Some utilities are experimentally investigating the effects of time-of-day pricing with industrial and residential customers.

6.2 SYSTEM DESIGN AND PLANNING UNCERTAINTY

Historically, utilities have treated separately the reliability criteria of generation, transmission, and distribution. Some are now beginning to address the problem of coupling these subsystems in an attempt to evaluate and optimize the overall system design. This is an important problem, because some have charged that the highly capital-intensive generation subsystem has been overbuilt and that the added reliability provided by the generation facilities does not benefit the customer because of the lower level of reliability in the transmission and distribution systems. Utilities have previously considered generation reliability as the critical component because of the long lead times necessary in its construction and because of the widespread effect imposed by deficient supply.

A contributing issue, therefore, in terms of utility practices relates to the long lead times required to construct new generating capacity. Much of the increase in lead time that developed in recent years is a result of regulatory delays. These have a significant effect on construction costs, planning uncertainty, and reliability. Some recent studies have attempted to analyze the social costs associated with over- or under-building generation capacity in view of future uncertainty,[2-6] and have concluded that the lesser costs are those associated with over-building. These results, however, are not founded upon detailed analyses of customer interruption costs nor evaluations of alternatives to new capacity construction; this class of study requires further investigation.

6.3 SYSTEM INTEGRATION OF NEW TECHNOLOGIES

New technologies will also have an effect on utility system reliability. The Department of Energy is developing several technologies that will be applicable for electric utility generation and others that might be used by the utility's customers. In the evaluation of DOE's development programs, it is necessary to consider the potential beneficial and adverse effects that these new technologies may have upon society.

A class of systems of interest to DOE is decentralized energy technologies (DET). These DETs are both electric and non-electric energy sources that are small in comparison to today's large centralized energy facilities and may be located near a load center or end-user. These systems may rely on conventional fuels or on renewable energy sources such as direct and indirect solar energy. The versatility of these small power systems enables them to be owned or controlled by the customer or by the utility, and they may be connected to or be independent of some centralized power network. Examples include solar photovoltaic, wind, run-of-river hydro, biomass conversion, cogeneration and energy storage technologies.

The key issues associated with this new breed of technologies encompass not only costs and environmental concerns but also, and perhaps of more importance, the effects of integrating these technologies into power systems as they are evolving when the DETs reach commercialization potential. Major issues that need to be resolved, if DETs are to be successfully implemented, are concerned with the optimum arrangement in terms of system ownership and control and the effects of the operation of DETs on society's energy infrastructure.

Those decentralized energy technologies, in particular, that rely on intermittent, renewable resources, such as direct solar conversion and wind generation, will have a component of availability totally dependent upon prevailing meteorological conditions. The extent to which the supply intermittence may correlate with customer demand is largely unknown, as are the mechanical forced outage rates associated with these technologies. These are critical factors in terms of the ability of these technologies to be integrated into the utility system.

System integration includes not only technical aspects but also economic, legal, institutional, and customer utility preferences. A major factor related to each of these areas is customer service reliability. Future use of solar-based technologies could save nonrenewable fossil and nuclear fuels, but there may be some added cost to the consumer. A component of that added cost may be in the form of decreased service reliability. The extent to which customers and utilities can tolerate changes in the level of reliability they now experience or provide, and the dollar and nondollar costs associated with those changes, is largely unknown. These are primary factors that will determine the acceptability of the new technolgies.

The evaluation of alternative DETs with respect to cost, reliability, ownership, and other aspects of system integration is the key to DOE's program decision process and will also aid in the definition of the optimum set of end-state social conditions. Subsequent studies can then evaluate alternative policies for evolving the desired end-state conditions.

6.4 HETEROGENEITY OF CUSTOMERS

Because of rising electricity costs coupled with a high overall inflation rate, utility customers and state regulatory commissions are beginning to seek methods by which a utility might more closely approximate and be more responsive to the heterogenous reliability requirements of its various customer classes. Nationally, the three major customer classes (residential, commercial, and industrial) each consume about a third of the total electric energy sales. Thus, in the provision of tailored reliability and the imposition of its associated costs, the utility needs also to consider equity among its various customer groups. Critical to this whole question of customer-tailored reliability is the practicality of providing a system capable of operating in this fashion.

6.5 RELIABILITY ASSESSMENT METHODOLOGY

Also important is the economic methodology employed in performing reliability analysis. Early work in the field has attempted to use a marginal micro-economic approach to illustrate that present reliability levels are too high. These studies, however, show a very broad minimum that is subject to considerable uncertainty. They also have little meaning in terms of the present price structure seen by the customer who pays, for the most part, only an average price for electricity. The closest approach to marginal pricing, and perhaps the only one that will ever be practical to apply, is some type of block rate structure that approximates incremental pricing. (On- and off-peak, time-of-day pricing is an example of a two-block structure.) If incremental electricity prices are not presented in the rate structure, the customer is not able to respond to them. Thus, since wide differences in reliability probably make only very small changes in the average price of electricity, the value of making a large effort to change customer service reliability is questionable.

6.6 LOAD SHEDDING PRIORITIES

From time to time when load shedding becomes necessary to maintain system integrity, the utility must decide which groups of customers are to be affected as well as how they are to be affected. At issue are the relative customer losses as functions of interruption frequency and duration and time of occurrence. The magnitude of the unquantified social costs incurred by some customer classes and the potential for other costs that have not yet been recognized by the utility analysts constitute another key problem area. Not every utility's load shedding priorities, then, should be, nor can be, the same because of the differences in the utility's physical configurations. The determination of socially optimal and equitable load shedding priorities will require further investigation and analysis of data not currently available. Without sufficient data for a large number of situations, it is difficult to determine the level to which generalizations might be made.

6.7 EMERGENCY POWER PURCHASES

Another important issue relates to the long-term effects associated with the choice made by some utilities of planning for a lower level of reliability than supplied by neighboring utilities. If they later attempt to provide a higher degree of customer service reliability through increased use of interties, obvious inequities would develop among the utilities that could generate a decrease in the level of cooperation now practiced by nation's utility industry. This type of situation might thus require federal action to mandate and regulate the level of reliability to be designed into each separate utility, or to regulate emergency power pricing.

The same type of situation might develop if U.S. utilities adopted a reliability level significantly lower than that of Canadian utilities. Apparent international conflicts could arise if the United States were to rely consistently on Canadian utilities for intertie power yet not be able to make return contributions. This type of situation might even have effects beyond the utility industry, and could also affect the United States negotiations on other energy products such as natural gas.

6.8 LOCAL ECONOMIC STABILITY

Little is known with regard to the long-term economic and quality-of-life effects associated with the adoption of lower levels of electric reliability. Questions now being raised are concerned with the long-term impacts of reliability on industrial site selection or relocation, and consequently on the employment potential within a service area. During a period of high unemployment and concern about socioeconomic impacts, the issue of industrial relocation is very important.

6.9 ENVIRONMENTAL DERATING

From time to time utilities are required to derate some of their generating stations because of environmental reasons -- high ambient air pollution or high thermal discharges. This type of requirement often occurs on hot summer days when electricity demand is quite high, and can place the utility in a critical situation with respect to its capacity sufficiency. To date, no detailed analysis has been performed that considers public health, safety, and economic factors in an attempt to provide a definite policy toward plant derating for environmental reasons.

6.10 NATIONAL TRANSMSISSION NETWORK

A final policy issue is that of a national transmission network. This proposed concept is an extension of the regional reliability council concept that was developed and implemented in the late 1960s. Formalization of a national transmission network would require additional interaction and co-operation between the regional reliability councils and the construction of new transmission facilities to strengthen existing interconnections particularly between the Rocky Mountain/Pacific Coast states and the Midcontinental/ Eastern states. A strong national transmission network would allow for the transfer of electrical power over long distances, and thus improve the reliability of all U.S. utilities. At issue is the cost-benefit ratio of such an endeavor. Are the added customer costs for new construction and administrative responsibilities, which may be partially offset by savings in generating capacity, worth the increment of reliability provided to the customer and nation? The concept of a national transmission network will likely evolve as an increasingly important regulatory and congressional issue in future years.

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4. *Optimal Capacity Planning Under Uncertainty in Demand*, Gordian Associates, prepared for the Federal Energy Administration (Nov. 1976), as cited in Ref. 1, p. 123.

5. Males, R.H., *System Reliability -- How Much Is Enough?*, before the American Public Power Association National Conference, Atlanta (May 8, 1978).

6. *How Much Is Enough? Reserves of 20-35% May be Cheaper for Customers*, Electrical Week, pp. 3-4 (May 15, 1978).

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APPENDIX A

METHODOLOGY USED IN SHIPLEY, PATTON, AND DENISON'S STUDY OF RELIABILITY*

Consider an existing electric utility system with a capital investment of I_o and a service availability (reliability) of A_o. Let system investment be separated into three components: generation, transmission, and distribution. Thus, for the existing system

$$I_o = I_{g_o} + I_{t_o} + I_{d_o} \tag{A.1}$$

where

I_{g_o} = investment in generation in existing system,
I_{t_o} = investment in transmission in existing system,
I_{d_o} = investment in distribution in existing system.

If we define the service availability of each of the three system components as

A_{g_o} = service availability of generation in existing system,

A_{t_o} = service availability of transmission in existing system, and

A_{d_o} = service availability of distribution in existing system,

then the availability of the existing system is

$$A_o = A_{g_o} A_{t_o} A_{d_o}. \tag{A.2}$$

Each component of the existing system is highly reliable, and thus has a service availability nearly equal to unity. Hence we may represent the availabilities of each component by

*Shipley, R.B., A.D. Patton, and J.S. Denison, *Power Reliability Cost vs. Worth* IEEE Transactions on Power Apparatus and Systems, pp. 2204-2212 (July-Dec. 1972).

$$A_{g_o} \approx 1 - \varepsilon_{g_o},$$
$$A_{t_o} \approx 1 - \varepsilon t_o, \text{ and}$$
$$A_{d_o} \approx 1 - \varepsilon_{d_o},$$

where ε_{g_o}, ε_{t_o}, and ε_{d_o} are positive and much less than unity. Substituting into A.2 we get

$$A_o \approx (1-\varepsilon_{g_o})(1-\varepsilon_{t_o})(1-\varepsilon_{d_o}). \tag{A.3}$$

Expanding the right-hand side of this equation gives

$$A_o \approx 1 - \varepsilon_{g_o} - \varepsilon_{t_o} - \varepsilon_{d_o} + \varepsilon_{g_o}\varepsilon_{t_o} + \varepsilon_{t_o}\varepsilon_{d_o} + \varepsilon_{g_o}\varepsilon_{d_o} - \varepsilon_{g_o}\varepsilon_{t_o}\varepsilon_{d_o}.$$

The last four terms are each products of two or more very small numbers and can be set equal to zero. Thus,

$$A_o \approx 1 - \varepsilon_{g_o} - \varepsilon_{t_o} - \varepsilon_{d_o}$$

or

$$A_o \approx 1 - (1-A_{g_o}) - (1-A_{t_o}) - (1-A_{d_o}),$$

then

$$A_o \approx A_{g_o} + A_{t_o} + A_{d_o} - 2. \tag{A.4}$$

Now suppose that the degree of redundancy in a component of the system, and hence the associated investment, is the only factor influencing availability. Supposing further that any network is composed of a number of the existing systems operating in parallel, the availability of the network in terms of the existing system is given as follows:

$$A_g = 1 - (1-A_{g_o})^{n_g}, \tag{A.5}$$

$$A_t = 1 - (1-A_{t_o})^{n_t}, \tag{A.6}$$

$$A_d = 1 - (1-A_{d_o})^{n_d}, \text{ and} \tag{A.7}$$

$$A = 1 - (1-A_{g_o})^{n_t} - (1-A_{t_o})^{n_t} - (1-A_{d_o})^{n_d} \tag{A.8}$$

where

n_g = number of existing generation systems operating in parallel,

n_t = number of existing transmission systems operating in parallel, and

n_d = number of existing distribution systems operating in parallel.

Then the total investment I in the network having availability A is

$$I = n_g I_{g_o} + n_t I_{t_o} + n_d I_{d_o}. \qquad (A.9)$$

Solving Eqs. A.5, A.6 and A.7 for n_g, n_t, and n_d and substituting in Eq. A.9 yields:

$$I = \frac{\ln(1-A_g)}{\ln(1-A_{g_o})} I_{g_o} + \frac{\ln(1-A_t)}{\ln(1-A_{t_o})} I_{t_o} + \frac{\ln(1-A_d)}{\ln(1-A_{d_o})} I_{d_o} \qquad (A.10)$$

This expression gives network investment in terms of the availabilities of the different components of each identical parallel system composing the network.

The cost of interruptions in terms of the availability of generation, transmission, and distribution components of the network is given by

$$C = k\ (1-A_g) + (1-A_t) + (1-A_d) \qquad (A.11)$$

where

C = cost of interruption, and

k = proportionality constant.

The generation, transmission, and distribution availabilities that minimize the total cost, I+C, are the solution of the following set of equations:

$$\begin{aligned} \frac{\partial I}{\partial A_g} + \frac{\partial C}{\partial A_g} &= 0 \\ \frac{\partial I}{\partial A_t} + \frac{\partial C}{\partial A_t} &= 0 \\ \frac{\partial I}{\partial A_d} + \frac{\partial C}{\partial A_d} &= 0 \end{aligned} \qquad (A.12)$$

Note that $\partial C/\partial A_g = \partial C/\partial A_t = \partial C/\partial A_d = -k$. Thus, the optimum network is achieved when the incremental cost of providing service availability is the same for each portion of the system and is equal to the incremental cost of service interruptions. Performing the operations indicated in Eq. A.12 and solving for the optimum availabilities yields

$$A_g = 1 + \frac{I_{g_o}}{k \ln(1-A_{g_o})},$$

$$A_t = 1 + \frac{I_{t_o}}{k \ln(1-A_{t_o})}, \text{ and} \qquad \text{(A.13)}$$

$$A_d = 1 + \frac{I_{d_o}}{k \ln(1-A_{d_o})}.$$

APPENDIX B

METHODOLOGY AND ASSUMPTIONS USED IN KAUFMAN'S STUDY OF RELIABILITY*

The following briefly summarizes and highlights the methodology and assumptions used by Alvin Kaufman in his cost-benefit analysis of electric utility system reliability in the New York Power Pool service area between 1974 and 1985. The author compares the costs and benefits resulting from loss of load probabilities of one day in ten years, five years, and one year.

1. An LOLP program is used to determine the relationship between LOLP and reserve margin as a percent of summer peak demand.

2. It is argued that the social benefits that accrue because of the provision of a generating reserve are equal to the value of the outages that do not occur. Thus, it is necessary to determine the number, severity, and length of loss of load incidents assuming no reserve capacity (items 3-6 below.)

3. The annual number of loss of load incidents <u>with no reserve</u> is determined using the LOLP program to generate the distribution of days per year that various percentages of peak load cannot be met. Load is not lost whenever demand surpasses available capacity because of standard operating procedures that allow an 8% voltage reduction to reduce load by 5% (Case A), and a 5% voltage reduction worth 3% of the peak load (Case B). Kaufman determines that 51 out of 260 days per year would have a loss of load incident with the ability to reduce voltage by 8%. A total of 156 days per year would have loss of load incidents if only a 5% voltage reduction were available.

4. The average severity of outages is then assumed to be the modal value of the outage distributions exclusive of the class of outages that would be covered by voltage reductions. For Case A, the modal severity is 7.7% of the peak and for Case B, it is 4.7% of the peak. Based on NYPP's load duration curve, these values are met or surpassed for 10 hr and 7 hr per year respectively, but Kaufman argues that it is not likely that they would be surpassed for these lengths of time on any single day.

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*Kaufman, A., *Reliability Criteria -- A Cost Benefit Analysis*, New York State Department of Public Service, Office of Research Report 75-9, Albany, N.Y. (June 1975).

5. The average length of outages, in the absence of reserve capacity was estimated by experienced engineers to range from 1 min to 4 hr. Kaufman assumes an average value of 2 hr. Thus, the outages that would occur in the absence of reserve capacity are:

   Case A) 51 outages/yr x 2 hr/outage = 102 hr/yr @ 7.7% of peak
   Case B) 156 outages/yr x 2 hr/outage = 312 hr/yr @ 4.7% of peak

6. Because the hours of estimated outage will be spread throughout the year, the peak on a given day will be less than the maximum annual peak. To compensate, Kaufman assumes the use of a winter peak in a summer peaking system. Thus, the outage severities in the absence of reserve capacity become 102 hr/yr at 7.7% of the <u>winter</u> peak and 312 hr/yr at 4.7% of the <u>winter</u> peak.

7. With no reserve, a small shortage in capacity leads to a loss of load. With reserves, however, the outages will be less frequent. With no apparent rationale, Kaufman selects the "average" outage <u>with reserves</u> available at 4 hours and to comprise 20% of the maximum (summer) peak. These are assumed to occur at a rate determined by the LOLP selected for analysis. In Kaufman's methodology the outages do not occur uniformly each year, but rather are assumed to occur in a single yearly period with the frequency of occurrence specified by the LOLP. That is, in the author's 12-year analysis loss of load occurs each year for the 1 d/yr LOLP; the first, sixth, and eleventh years for the 1 d/5 yr LOLP; and the first and eleventh years for the 1 d/10 yr LOLP. In all other years, no outages occur. (Note that the author's assumptions for the 1 d/5 yr LOLP and the 1d/10 yr LOLP cases really assume a 1 d/4 yr and a 1 d/6 yr LOLP because the analysis is performed for only 12 years.)

8. The benefit that accrues to society is the present value of: the economic losses that would have occurred if no reserve margin was provided, less the stream of losses that occur when the reserve margin is present, less the owning and operating costs of the peaking capacity.

9. Owning and operating costs are determined assuming sunk costs prior to 1974; new peaking capacity additions at $130/kW plus 5% annual inflation; $0.70/Kw fixed charges plus $0.60/kWh fired; and a 20% charge on the capital cost of the reserve capacity for capital, tax, and miscellaneous expenses.

   Upon checking Kaufman's calculations, it was found that the the total cost of new peaking units was added to the annual owning and operating cost in the year that capacity was installed. The 20% charge was levied against this cost each successive year, which is contrary to the author's expressed assumption and double-counts the capital cost of new capacity.

10. The value of social losses per megawatt-hour of unserved energy is determined in the following manner: A loss factor as the ratio of New York State value added to total state electric revenues ($VA/$REV). This factor is then multiplied by the incremental unit cost of the peaking reserve which is defined as the ratio of annual peaking reserve owning and operating costs divided by the megawatt-hours of annual operation ($ peak operating costs/ MW reserve x 2 hr/d x 260 d/yr). The value of social losses is assumed to escalate at 2% per year. Resultant estimates for social losses are $770/Mwh in 1974 and $1270/Mwh in 1985.

Kaufman is inconsistent in his estimate of social losses per megawatt-hour of unserved energy. The factor defined as the ratio of New York state value added to total electric revenues can be written as the ratio of value added divided by the product of total megawatt-hours times the average sale price per megawatt-hour, or

$$\frac{\$VA}{\$REV} = \frac{\$VA}{\text{Total MWH}} \times \frac{1}{\text{Avg }\$/\text{MWH}}$$

The unit cost of providing reserve generation is a <u>incremental</u> cost

$$\begin{array}{l}\text{Unit Reserve}\\ \text{Generation Costs}\end{array} = \text{INC }\$/\text{MWH}$$

It is inconsistent to calculate consumer losses per megawatt-hour of unserved energy by multiplying value added per dollar of <u>average</u> electric energy revenues times the <u>incremental</u> unit generation costs for peaking capacity as the author has done. That is

$$\frac{\$VA}{\$REV} \times \begin{array}{l}\text{Unit Reserve}\\ \text{Generation Costs}\end{array} = \frac{\$VA}{\text{Total MWH}} \times \frac{1}{(\text{Avg }\$/\text{MWH})} \times (\text{INC }\$/\text{MWH})$$

This does <u>not</u> equal $\frac{\$VA}{\text{Total MWH}} \times \frac{1}{(\text{Avg }\$/\text{MWH})}$ as the author has assumed. Using Kaufman's data, the incremental cost of providing peaking generation is about twice as great as the average sale price of electricity. Therefore, he overestimates consumer losses by approximately a factor of two.

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