A DEMONSTRATION OF THE MARGINAL COST APPROACH TO TIME OF USE PRICING OF ELECTRIC SERVICE

prepared by
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FOREWORD

The National Regulatory Research Institute (NRRI) was established at the Ohio State University in 1977 by the National Association of Regulatory Utility Commissioners to provide state regulatory commissions with technical assistance and timely, high level policy research on regulatory issues.

This report is one of a series of publications resulting from on-site technical assistance projects supported by the U. S. Department of Energy (DOE) and directed by the NRRI. The purpose of these technical assistance projects is to provide in-depth studies in specific areas of utility regulation as requested by various state regulatory agencies. A concern of the DOE is for the prudent management and conservation of our national energy resources. Accordingly, it is believed that assistance should be provided to state regulatory agencies in husbanding the energy resources within their state boundaries. Funding availability has limited these efforts such that not all state agencies requesting assistance could be served at first. One criterion for selecting a particular state assistance project was the potential for that project to possibly provide guidance to other regulatory agencies with similar or related problems. It is with that thought in mind that the results of several of the individual state technical assistance projects are being published and made available to others.

PREFACE

This study, authorized on 19 July 1978 by the National Regulatory Research Institute (NRRI), has two primary purposes. First, it is intended to introduce the staff of the Idaho Public Utilities Commission to time-of-use pricing of electricity based on marginal cost. Second, it is intended to illustrate such pricing using available data from the Utah Power and Light Company (UP&L).

CH2M HILL wishes to thank those people who assisted us in making this study. In particular, our thanks go to Mr. John H. Willmorth, utility engineer of the Idaho Commission, and to Ms. Mary Wiedl and Mr. Mike Eperson of the Commission staff. Our thanks also go to Messrs. Albert Dunn, James Taylor, and Dean Bryner, who arranged for us to obtain the data from the Utah Power and Light Company.

Last, but by no means least, we gratefully acknowledge the help of Mr. John C. Cuddy of the National Regulatory Research Institute.

SUMMARY

PURPOSES OF TIME-OF-USE PRICING

The adoption of time-of-use pricing of electric service has been urged for several years by economists and others who believe that such pricing will more nearly match rates to costs and will also result in either the shifting of loads from peak periods to nonpeak periods or will result in on-peak users reducing their use during peak periods. In either event, such customer responses would reduce the amount of capacity needed to meet future loads. This would be a decided advantage both to the utilities and to their customers and would result in smaller rate increases in future years. The extent to which such changes in peak load usage will actually result from the adoption of time-of-use prices is far from clear at this time for two reasons: Virtually no reliable statistical data on customer response to experimental time-of-use electric rates in the U.S. are yet available. Further, it appears unlikely that when such data do become available they can be used to reliably forecast results on other electric systems unless they have nearly similar rate levels and load characteristics.

However, with the growing interest in rate reform, it is important that state utility regulatory agencies become completely familiar with time-of-use pricing and current methods of developing such pricing.

USE OF MARGINAL COST AS A BASIS FOR TIME-OF-USE PRICING

While it is clear that time-of-use prices for electricity could be based oneither average or marginal costs, there are some theoretical arguments in favor of using marginal costs.

First, the shifts in customer usage of electricity will not have any effect on the existing investment in generation, transmission, and distribution facilities. Such shifts can only affect future utility investments and these investments will be made at marginal cost, not average cost. Second, rates based on marginal cost will signal customers that future costs will be different from present costs and will presumably encourage them to change their consumption habits so as to reduce their contribution to peak loads on the utility system.

SELECTION OF METHODOLOGY

Among the most ardent promoters of marginal cost-based time-of-use electricity rates is the consulting firm, National Economic Research Associates, Inc. NERA made the studies of marginal cost pricing for the Electric Power Research Institute's study of electric rate reform. NERA has also presented such studies before a number of state regulatory commissions in both utility rate increase proceedings and in generic rate hearings.

Because of this wide dissemination, the NERA methodology was selected to demonstrate the development of marginal cost-based time-of-use rates for the Idaho Commission.

SOURCES OF DATA

The Utah Power and Light Company cooperated in this study by furnishing data on its system for the studies. Not all of the information required by the NERA methodology was available from the company, however, and data from other studies were substituted where Utah Power and Light data were unavailable.

For example, no data on customer response to electric rate changes are currently available for the Utah Power and Light Company system. The elasticities used in the report have therefore been assumed on the basis of the results of other studies. For this reason this demonstration study is not developed for direct introduction into rate proceedings before the Idaho Commission.

CONCLUSIONS

While this study of marginal cost-based time-of-use pricing is not developed for use in current rate proceedings, it is believed to have served its purpose as a guide in training the Idaho Commission staff in the methods and procedures of making such a study. With more time to collect definitive data, the Commission staff will be able to develop studies for ratemaking pruposes in the future.

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* * *

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Chapter 1
NERA APPROACH

National Economic Research Associates, Inc. (NERA) has developed a standard procedure to quantify marginal costs. NERA describes its approach as "forward-looking, marginalist in nature and requiring an understanding of cost causation and the interrelationships between cost elements." The methodology is necessarily flexible, due to differences in utility system characteristics and problems with data availability. It is not practical to examine all the possible variations in NERA methodology; however, in this chapter we will examine the basic framework NERA uses to quantify marginal costs. Chapter 2, *Application of Methodology and Results*, provides a detailed step-by-step guide to marginal cost pricing.

Because marginal cost pricing of electricity is a relatively new concept it is sometimes useful to compare it to the more familiar and commonly used average cost pricing method. Both pricing models seek to determine and allocate capacity-, energy-, and customer-related costs to classes of customers. However, unlike average cost pricing, marginal cost pricing is not directed toward the revenue requirement of the utility. Marginal costs are based on future replacement costs in current dollars, rather than on the historical average embedded costs. (It is often necessary to analyze historical costs to arrive at marginal costs, but the results are always in current replacement costs rather than historical costs.)

Allocation of Marginal Costs

Time-of-use pricing adds another dimension to the marginal cost approach by allocating capacity and energy costs not only by customer class but by seasonal and/or daily peak periods. Allocation of capacity and energy costs to the peak period results in an efficient allocation of resources in that customers who are contributing to the peak load are charged for the capacity needed to serve that load. NERA develops peak costing/pricing periods by examining loss of load probabilities (LOLP), the probability that load will exceed capacity in any given period, on a monthly and daily basis. The months and hours having the highest LOLP are grouped into seasonal and daily peak periods. Seasonal and daily allocation factors, developed from LOLP in peak and off-peak periods, are used to allocate capacity costs to the selected seasonal and daily peak and off-peak periods.

Capacity-Related Marginal Costs

The marginal demand-related cost of generation transmission and distribution is the incremental investment cost and associated O&M costs to serve an additional kW of peak demand. NERA proposes that the marginal cost of generation capacity would be the cost of the plant used for the shortest duration to meet the load at peak. In most cases it would be the current investment cost of a peaking plant. The marginal investment in transmission facilities is determined by analyzing the cost of transmission investment necessary to meet increases in load over a historical and future time period. Transmission investment is analyzed over a period of time because transmission investment is often uneven; transmission capacity built in any given year may be designed to serve increases in load over the next 5 years. The total investment (in current dollars) in transmission investment over the selected time period divided by the total increase in peak demand results in the marginal demand-related unit cost of transmission facilities. The marginal investment in distribution facilities is determined, for the most part, the same way. A shorter period for analysis is allowed because investment in distribution facilities is not as uneven as investment in transmission facilities. Once the unit investment is determined, an additional step is required.

It is generally recognized that a distribution system is comprised of two cost components, customer and capacity. The customer-related cost, that which does not vary with demand, is the cost of providing a minimum system of distribution, and is allocated on a per-customer basis. This customer-related cost is subtracted from the total marginal distribution cost to arrive at the demand-related marginal cost of distribution plant.

Once the marginal demand-related costs of generation, transmission, and distribution are calculated, they are then adjusted to include the costs of associated operation and maintenance expense, related general plant investment, administrative and general plant expenses, working capital, interest, depreciation, taxes, and return on equity. These are then annualized over the life of the investment to arrive at the total annual marginal demand-related cost of generation, transmission, and distribution plant. The final step in calculating marginal capacity cost is to apply capacity loss factors to the above costs to produce marginal capacity costs by delivery voltage. Those final costs are allocated to seasonal and daily peak and off-peak periods by the LOLP capacity allocation factors.

Energy-Related Marginal Costs

Marginal energy costs at any point in time can be defined as the running cost (fuel and variable O&M cost) of the generating unit having the highest variable cost (generally the last unit on line) at the optimal generation mix. This concept, known as system "lambda," is calculated as the cost of the next increment in load. As in the case of capacity costs, the running costs must be grouped to represent costs in peak and off-peak periods.

Once peak and off-peak running costs have been determined, these are adjusted to include the incremental associated costs of administrative and general expense, cost of capital, and working capital. Marginal energy loss factors are then applied to arrive at marginal energy costs by delivery voltage.

Customer-Related Marginal Costs

The customer portion of marginal distribution costs (the cost of providing a minimum distribution system), customer accounts expense, and sales expense comprise the remaining cost component, marginal customer cost.

Customer accounts expense and sales expense are determined by extrapolating historical trends and adjusting weighted customer factors to arrive at customer accounts expense and sales expense by customer class. These expenses are added to the customer-related distribution cost which is adjusted to include the incremental costs of associated O&M expense, related general plant investment, administrative and general plant expense, working capital, depreciation, taxes, interest on debt, and return on equity. The result is marginal unit customer-related cost by class of customer. Since customer costs are not related to capacity or energy consumption, they are not allocated daily or seasonally.

Chapter 2
APPLICATION OF METHODOLOGY AND RESULTS

In this chapter NERA's marginal cost pricing methodology is applied to the Utah Power and Light system to obtain costing/pricing periods, marginal costs of capacity and energy, and marginal customer costs. The procedures and results of this are summarized in Schedules 1.0 through 9.1 and in the following text. The appendix, arranged by schedule number, contains original worksheets, responses to data requests, and backup material to the schedules. The schedule numbers follow the Marginal Cost Pricing Procedure Flow Chart diagrammed in figure 1.

Schedule 1.0--Derivation of Cost/Price Time Periods

Costing/pricing periods are determined by grouping periods of similar capacity costs through analysis of loss of load probability data. Ideally, load data should be examined on a daily and monthly basis to determine daily and seasonal peak periods. Actual loss of load probability data were not available for Utah Power and Light; however, sample data in Schedule 1.0 illustrate the methodology used to calculate seasonal costing/pricing periods and corresponding allocation factors. Due to the lack of data for UP&L, seasonal costing/pricing periods were determined by reviewing the monthly peak demands and grouping peak and off-peak months. (see figure 2). The allocation factors for peak and off-peak seasons were estimated at 60 percent and 40 percent, respectively. Through analysis of daily load curves the peak hours were determined to be 5 a.m. to 11 p.m. Monday through Friday. Although the hour from 5 to 6 a.m. and the hour from 10 to 11 p.m. are not currently peak hours, they have the potential of becoming shoulder peaks and therefore were included in the daily peak period. Capacity costs will be allocated 100 percent to the daily peak period.

Schedules 2.1.1-2.1.3 and 2.2.1-2.2.3--Calculation of Present Value of Revenue Requirements and Economic Carrying Charges

In this task, the analyst must compute the present value of the stream of charges that will arise from incremental capital investment. Schedules with a 2.1 prefix calculate the revenue requirement, or the return that must be realized on the investment to cover depreciation, taxes, interest, and return on equity. Because the service life of plant under each function--generation, transmission, and distribution--is different, each function will have its own "carrying charge," which is used to amortize the investment over the life of the plant. The carrying charges are calculated in schedules with a 2.2 prefix.

Schedule 3.0--Computation of Loading Factors for A&G Expenses, FICA, and Unemployment Insurance Taxes

These factors are used in computing the annual carrying charges to incorporate overhead expenses and taxes into plant capital costs and operation and maintenance expenses. The labor-related A&G loading factor, developed from labor-related costs, is applied to all marginal demand-related operation and maintenance expenses. The plant A&G loading factor, developed from plant-related expenses, is applied to marginal plant investment costs. The energy A&G loading factor is applied to the marginal energy costs.

Schedules 4.1 and 4.2--Development of Capacity and Energy Adjustment Factors

In order to compute unit costs at the delivery voltage, the marginal costs computed must be adjusted by the appropriate transformation and tranmission losses that occur from generation to the delivery voltage. These schedules show the loss factor that must be applied to capacity and energy costs to compensate for losses at each delivery voltage.

Schedule 5.1.3--Marginal Costs--Generation

In this example, three steps have been combined into one table. The marginal investment in generation facilities was estimated by CH2M HILL, using the cost of a combustion turbine adjusted for planned reserve margin. This investment cost was then annualized and loaded with the appropriate "carrying" costs, A&G factor, O&M costs, and working capital to arrive at the total demand-related marginal cost of generation.

Schedule 5.1.4--Allocate Marginal Generation Costs to Costing Periods

From the results of 5.1.3 adjusted for losses from 4.1, the generation costs were allocated to the costing periods based on the results from 1.0. To arrive at unit costs, a further adjustment, representing the relative mean peak demand, was applied.

Schedule 5.2.1--Derivation of Marginal Investment of Transmission Facilities

By examining the historical and projected load-related additions to plant in 1978 dollars and their corresponding addition to system capability, a dollars per kilowatt amount was calculated representing the marginal interest.

Schedule 5.2.2--Transmission Expense

Based on an examination of the historical relationship of expenses to addition to system demand at peak, future transmission expenses were projected. These future costs, adjusted to 1978 dollars, represent the marginal transmission expense.

Schedule 5.2.3--Computation of Marginal Unit Costs--Demand-Related Transmission

The investment derived in 5.2.1 was loaded with general plant, energy charge, and A&G. This amount is annualized and included with the appropriate O&M, A&G, and working capital costs to arrive at the total marginal cost on a peak kW basis.

Schedule 5.2.4--Allocate Marginal Transmission Costs to Costing Period

This step is the same process as described in 5.1.4.

Schedule 5.3.1--Derivation of Customer Component of Marginal Investment in Distribution Facilities

Using 1978 dollars, this schedule derives the minimum cost to provide service to customers at distribution service level. Data for Utah Power and Light were not available; therefore, the cost of a minimum distribution system for a West Coast utility (adjusted for regional price differential) was used.

Schedule 5.3.2--Distribution Expense Customer Component

This step is similar to Schedule 5.2.2, except derived marginal expenses are then split between customer and demand components, 60 percent customer, 40 percent demand. The customer component is then divided by the number of customers to arrive at a dollars per customer figure.

Schedule 5.3.3--Computation of Marginal Unit Costs--Customer-Related Distribution

This step is similar to 5.2.3 except customer accounts and sales expenses are also added to arrive at total marginal customer-related costs. Note: customer accounts and sales expenses are derived in Schedules 6.1 and 6.2.

Schedule 5.4.1--Derivation of Demand Component of Marginal Investment in Distribution Facilities

This step examines the historical and projected additions to plant in 1978 dollars, less the customer-related portion (5.3.1), and divides the residual by the increase in system peak demand.

Schedule 5.4.2--Distribution Expense--Demand Component

The 40-percent portion, as derived in Schedule 5.3.2, is divided by system peak demand, giving demand-related expenses on a dollars per kilowatt basis in 1978 dollars.

Schedule 5.4.3--Computation of Marginal Unit Costs--Demand-Related Distribution

This step is similar to Schedule 5.2.3.

Schedule 5.4.4--Allocate Marginal Distribution--Demand-Related Costs to Costing Period

This step is the same process as described in Schedule 5.1.4.

Schedule 6.1--Customer Accounts Expense

Historical customer accounts expense was adjusted by a composite customer weighting factor to obtain a per customer cost in each year. These costs were then adjusted to 1978 dollars and analyzed to determine the historical trend in unit customer accounts expense.

Schedule 6.1.1--Customer Accounts by Class of Service

For most customer costs, the average cost per customer varies significantly from one class to another. It is therefore necessary to weight, by judgment, the number of customers in each class to reflect this relative cost differential. For example, costs associated with an industrial meter are estimated to be ten times higher than for a residential meter, so that the number of customers in each class is weighted accordingly for allocating total meter costs. Weighting factors for each customer class were applied to the unit customer accounts expense calculated in Schedule 6.1 to arrive at customer account expense by class of service.

Schedule 6.2--Sales Expense

Same procedure as Schedule 6.1.

Schedule 6.2.1--Sales Expense by Class of Service

Same procedure as Schedule 6.1.1.

Schedule 7.0--Derivation of Annual Marginal Street Lighting Costs

The incremental investment according to each type and size of lamp must be calculated, and general plant, carrying charge, and A&G expenses summed. After annualizing, the above investment costs, O&M, A&G, and power costs are summed to arrive at the annual marginal street lighting costs. This procedure must be done for each street lighting rate schedule. No data were available for this schedule.

Schedule 8.1--Derivation of Marginal Running Costs

Marginal running costs, which include fuel and operation and maintenance costs, are usually available from the utility. However, these data were not available for this study; therefore, the marginal running costs were estimated by averaging the fuel costs of all the steam generating plants in the Utah Power and Light system. The fuel cost of the peaking plants was used for the peak period marginal running cost, and the fuel cost of the base-load plants was used for the off-peak marginal running cost.

Schedule 8.2--Derivation of Marginal Running (Energy) Costs By Costing Period

The marginal running costs derived in Schedule 8.1 were adjusted to incorporate energy-related A&G expense and working capital. These amounts were then adjusted for losses at each delivery voltage level to arrive at marginal energy costs by costing period and service voltage.

Schedule 9.0--Summary of Marginal Costs by Costing Period and Customer Class

Costs derived from Schedules 5.1.4, 5.2.4, 5.3.3, 5.4.4, and 8.0 are shown by class of service. The results are the marginal demand cost and energy cost for each customer class.

Schedule 9.1--Summary of Marginal Customer Costs By Customer Class

Summary of 5.3.3.

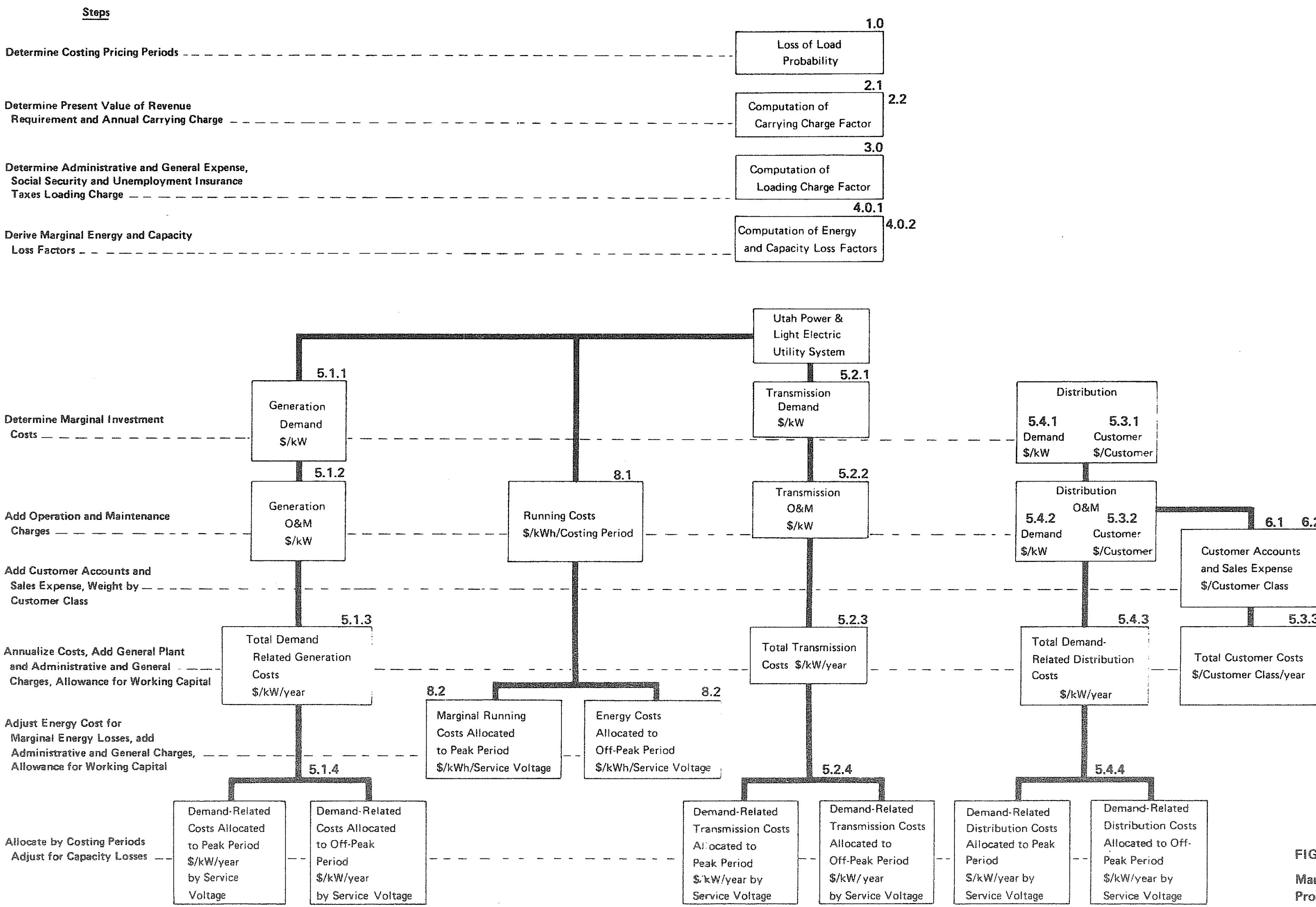


FIGURE 1

Marginal Cost Pricing Procedural Flow Chart

UTAH POWER AND LIGHT
CALCULATION OF RELATIVE MEAN VALUE OF LOSS-OF-LOAD
PROBABILITIES BY COSTING PERIOD
(for Illustration Only)

	Costing Period	(1) LOLP[1]	(2) Monthly Mean LOLP	(3) Relative Value of LOLP
		--(days per year)--		
	Peak Months			
1.	October	1.401		
2.	November	3.690		
3.	December	3.382		
4.	January	0.849		
5.	February	2.487		
6.	March	1.176		
7.		12,985	2.164[2]	0.87[4]
	Off-Peak Months			
8.	April	0.459		
9.	May	0.113		
10.	June	0.338		
11.	July	0.227		
12.	August	0.274		
13.	September	0.503		
14.		1.914	0.319[3]	0.13[5]

[1] Ten-year average of company loss-of-load probabilities.

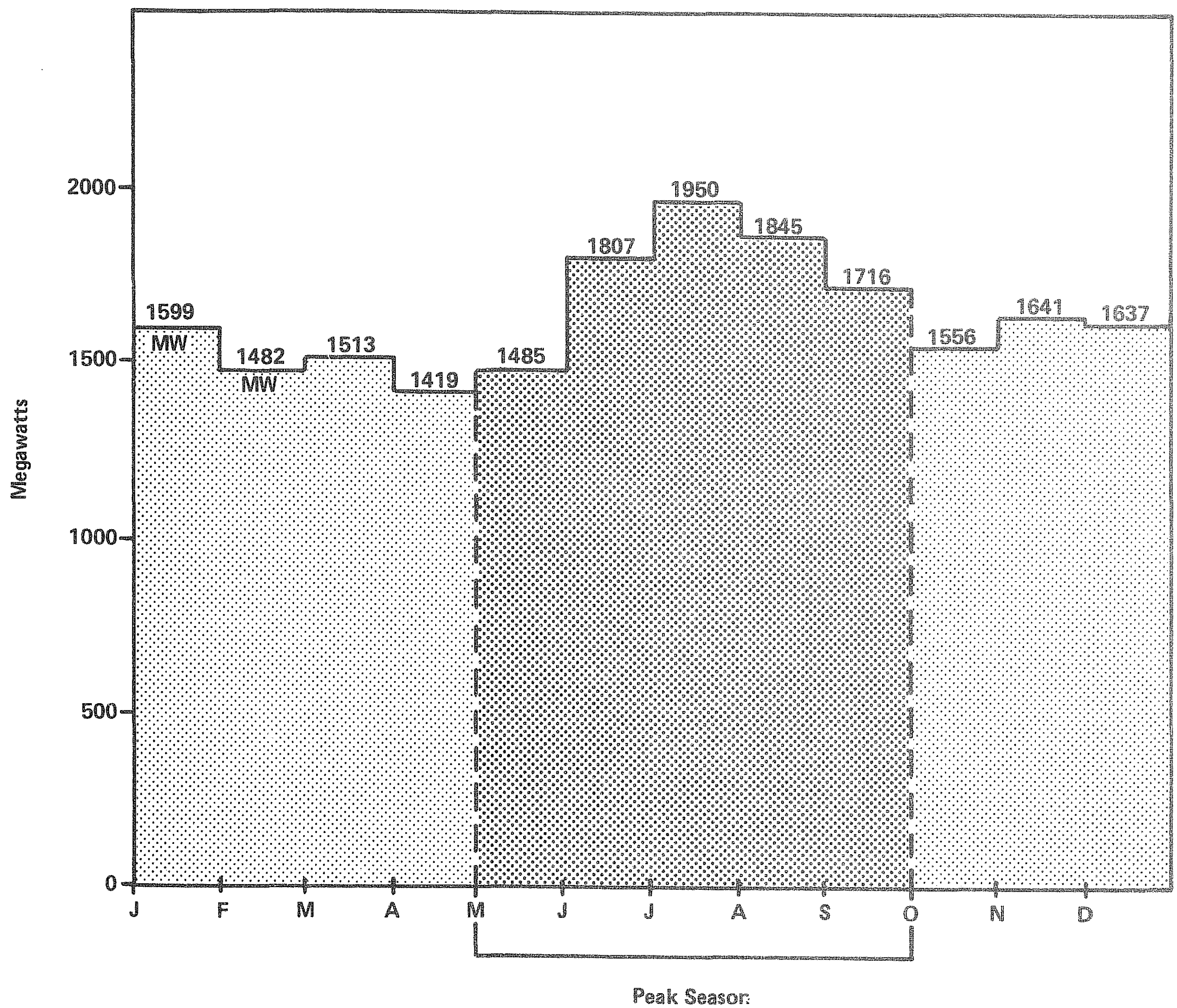
[2] Column 1, line 7 ÷ number of months in period (6).

[3] Column 1, line 14 ÷ number of months in period (6).

[4] Column 2, line 7 ÷ column 2, lines 7 + 14.

[5] 1 - column 3, line 7.

NOTE: Because LOLP data were not available for Utah Power and Light actual data from a winter peaking system were used for illustration purposes. For figures actually used in this study see figure 2.



Source: FPC Form 12

FIGURE 2

UTAH POWER AND LIGHT
MONTHLY SYSTEM PEAKS 1977

UTAH POWER AND LIGHT
CALCULATION OF PRESENT VALUE OF REVENUE REQUIREMENTS
RELATED TO INCREMENTAL $1,000 INVESTMENT[1]
GENERATION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
		Mean Annual	Book Deprecia-		Book Depreciated	Mean Net Book	Tax Deprecia-	Deferred Income	Deferred Tax	Investment Tax Credit		
	Year[1]	Survivors	tion	Retirements	Reserve	Investment	tion	Tax	Reserve	Credit	Amorti-zation	Reserve
		$										
1.	1	1,000	28	0	0	1,000	85.11	28.62	0	100	2.78	0
2.	2	1,000	28	0	28	972	81.32	26.67	28.62	0	2.78	97.22
3.	3	1,000	28	0	56	944	77.54	24.78	55.29	0	2.78	94.44
4.	4	1,000	28	0	84	916	73.76	22.89	80.07	0	2.78	91.66
5.	5	1,000	28	0	112	888	69.98	21.00	102.96	0	2.78	88.88
6.	6	1,000	28	0	140	860	66.19	19.10	123.96	0	2.78	86.10
7.	7	1,000	28	0	168	832	62.41	17.21	143.06	0	2.78	83.32
8.	8	1,000	28	0	196	804	58.63	15.32	160.27	0	2.78	80.54
9.	9	1,000	28	0	224	776	54.85	13.43	175.59	0	2.78	77.76
10.	10	1,000	28	0	252	748	51.06	11.53	189.02	0	2.78	74.98
11.	11	1,000	28	0	280	720	47.28	9.64	200.55	0	2.78	72.20
12.	12	1,000	28	0	308	692	43.50	7.75	210.19	0	2.78	69.42
13.	13	1,000	28	0	336	664	39.72	5.86	217.94	0	2.78	66.64
14.	14	1,000	28	0	364	636	35.93	3.97	223.80	0	2.78	63.86
15.	15	1,000	28	0	392	608	32.15	2.08	227.77	0	2.78	61.08
16.	16	1,000	28	0	420	580	30.15	1.08	229.85	0	2.78	58.30
17.	17	1,000	28	0	448	552	30.14	1.07	230.93	0	2.78	55.52
18.	18	1,000	28	0	476	524	30.14	1.07	232.00	0	2.78	52.74
19.	19	1,000	28	0	504	496	30.14	1.07	233.07	0	2.78	49.96
20.	20	1,000	28	0	532	468	0	-14.00	234.14	0	2.78	47.18
21.	21	1,000	28	0	560	440	0	-14.00	220.14	0	2.78	44.40
22.	22	1,000	28	0	588	412	0	-14.00	206.14	0	2.78	41.62
23.	23	1,000	28	0	616	384	0	-14.00	192.14	0	2.78	38.84
24.	24	1,000	28	0	644	356	0	-14.00	178.14	0	2.78	36.06
25.	25	1,000	28	0	672	328	0	-14.00	164.14	0	2.78	33.28
26.	26	1,000	28	0	700	300	0	-14.00	150.14	0	2.78	30.50
27.	27	1,000	28	0	728	272	0	-14.00	136.14	0	2.78	27.72
28.	28	1,000	28	0	756	244	0	-14.00	122.14	0	2.78	24.94
29.	29	1,000	28	0	784	216	0	-14.00	108.14	0	2.78	22.16
30.	30	1,000	28	0	812	188	0	-14.00	94.14	0	2.78	19.38
31.	31	1,000	28	0	840	160	0	-14.00	80.14	0	2.78	16.60
32.	32	1,000	28	0	868	132	0	-14.00	66.14	0	2.78	13.82
33.	33	1,000	28	0	896	104	0	-14.00	52.14	0	2.78	11.04
34.	34	1,000	28	0	924	76	0	-14.00	38.14	0	2.78	8.26
35.	35	1,000	28	0	952	48	0	-14.00	24.14	0	2.78	5.48
36.	36	1,000	20	0	980	20	0	-10.14	10.14	0	2.70	2.70

[1] Average life of generation plant = 36 years.

UTAH POWER AND LIGHT
CALCULATION OF PRESENT VALUE OF REVENUE REQUIREMENTS
RELATED TO INCREMENTAL $1,000 INVESTMENT
GENERATION

Schedule 2.1.1
page 2 of 3

		(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
										Present Value		
	Year	Mean Net Investment	Equity Return	Interest	Taxable Income	Investment Tax Credit	Income Tax	Ad Valorem Tax	Revenue Requirements	$1 @ 10.45%	Mean Annual Survivors	Revenue Requirement
		$										
1.	1	1,000	64.50	40.00	66.62	100.00	-16.73	13.00	254.61	0.90539	905.39	230.52
2.	2	943.38	60.85	37.74	70.31	0	35.24	12.64	198.36	0.81973	819.73	162.60
3.	3	888.71	57.32	35.55	59.70	0	29.92	12.27	185.06	0.74217	742.17	137.35
4.	4	835.93	53.92	33.34	56.68	0	28.41	11.91	175.69	0.67195	671.95	118.05
5.	5	785.04	50.64	31.40	53.89	0	27.01	11.54	173.77	0.60838	608.38	105.72
6.	6	736.04	47.47	29.44	51.32	0	25.72	11.18	158.13	0.55081	550.81	87.10
7.	7	688.94	44.44	27.56	49.04	0	24.58	10.82	149.83	0.49870	498.70	74.72
8.	8	643.73	41.52	25.75	46.97	0	23.54	10.45	141.80	0.45152	451.52	64.03
9.	9	600.41	38.73	24.02	45.17	0	22.64	10.09	134.13	0.40880	408.80	54.83
10.	10	558.98	36.05	22.36	43.58	0	21.84	9.72	126.72	0.37012	370.12	46.90
11.	11	519.45	33.50	20.78	42.26	0	21.18	9.36	119.68	0.33510	335.10	40.10
12.	12	481.81	31.08	19.27	41.20	0	20.65	9.00	112.97	0.30340	303.40	34.28
13.	13	446.06	28.77	17.84	40.36	0	20.23	8.63	106.55	0.27469	274.69	29.27
14.	14	412.20	26.59	16.49	39.80	0	19.95	8.27	100.49	0.24870	248.70	24.99
15.	15	380.23	24.52	15.21	39.43	0	19.76	7.90	94.69	0.22517	225.17	21.32
16.	16	350.15	22.58	14.01	37.55	0	18.82	7.54	89.25	0.20387	203.87	18.20
17.	17	321.07	20.71	12.84	33.80	0	16.94	7.18	83.96	0.18458	184.58	15.50
18.	18	292.00	18.83	11.68	30.03	0	15.05	6.81	78.66	0.16712	167.12	13.15
19.	19	262.93	16.96	10.52	26.28	0	13.17	6.45	73.39	0.15130	151.30	11.10
20.	20	233.86	15.08	9.35	52.73	0	26.43	6.08	68.16	0.13699	136.99	9.34
21.	21	219.86	14.18	8.79	50.92	0	25.52	5.72	65.43	0.12403	124.03	8.12
22.	22	205.86	13.28	8.23	49.12	0	24.62	5.36	62.71	0.11229	112.29	7.04
23.	23	191.86	12.37	7.67	47.29	0	23.70	4.99	59.95	0.10167	101.67	6.10
24.	24	177.86	11.47	7.11	45.49	0	22.80	4.63	57.23	0.09205	92.05	5.27
25.	25	163.86	10.57	6.55	43.68	0	21.89	4.26	54.49	0.08334	83.34	4.54
26.	26	149.86	9.67	5.99	41.88	0	20.99	3.90	51.77	0.07546	75.46	3.91
27.	27	135.85	8.76	5.43	40.06	0	20.08	3.54	49.03	0.06832	68.32	3.35
28.	28	121.86	7.86	4.87	38.25	0	19.17	3.17	46.29	0.06185	61.85	2.86
29.	29	107.86	6.96	4.31	36.45	0	18.27	2.81	43.57	0.05600	56.00	2.44
30.	30	93.86	6.05	3.75	34.62	0	17.35	2.44	40.81	0.05070	50.70	2.07
31.	31	79.86	5.15	3.19	32.82	0	16.45	2.08	38.09	0.04591	45.91	1.75
32.	32	65.86	4.25	2.63	31.01	0	15.54	1.72	35.36	0.04156	41.56	1.47
33.	33	51.86	3.34	2.07	29.19	0	14.63	1.35	32.61	0.03763	37.63	1.23
34.	34	37.86	2.44	1.51	27.39	0	13.73	0.99	29.89	0.03407	34.07	1.02
35.	35	23.86	1.54	0.95	25.58	0	12.82	0.62	27.15	0.03085	30.85	0.84
36.	36	9.86	0.64	0.39	23.78	0	11.92	0.26	24.43	0.02793	27.93	0.68
37.	Total										9,302.15	1,351.76

DERIVATION OF COLUMNS:

1. Incremental investment of $1,000 assumed.
2. Composite book (straight line) depreciation 2.8% x investment (col. 1). From FPC Form 1, composite of calendar year 1977.
3. No retirements assumed.
4. Cumulative of column 2.
5. Column 1 - column 4.
6. Sum of the years digits depreciation to year 16, straight line thereafter. From FPC Form 1, composite of calendar year 1977.
7. Tax rate (composite federal and state income tax rate supplied by UP&L (50.12%) x (col. 6 - col. 2).
8. Cumulative of column 7.
9. Current investment tax credit of 10% in the year investment is made.
10. Amortization of $100 over 36 years (100 ÷ 36).
11. Investment tax credit of $100 less annual amortization (col. 9).
12. Col. 1 - (col. 4 + col. 8).
13. Weighted cost of preferred debt (.85%) and common equity (5.6%) x col. 12.
14. Weighted cost of long-term debt (4.0%) x col. 12.
15. (Col. 2 - col. 6 - col. 10 + col. 13) ÷ (1 - effective tax rate).
16. Current investment tax credit of 10% in the year investment is made.
17. Effective tax rate (50.12%) x (col. 15 - col. 16).
18. Ad valorem tax rate (1.3%) x col. 5.
19. (Col. 2 + col. 7 - col. 10 + col. 13 + col. 14 + col. 16 + col. 17 + col. 18).
20. Present value of $1.00 discounted at future overall cost of capital (10.45%).
21. Col. 1 x col. 20.
22. Col. 19 x col. 20.

UTAH POWER AND LIGHT
CALCULATION OF PRESENT VALUE OF REVENUE REQUIREMENTS
RELATED TO INCREMENTAL $1,000 INVESTMENT[1]
TRANSMISSION

	Year[1]	(1) Mean Annual Survivors	(2) Book Deprecia-tion	(3) Retirements	(4) Book Depreciated Reserve	(5) Mean Net Book Investment	(6) Tax Deprecia-tion	(7) Deferred Income Tax	(8) Deferred Tax Reserve	(9) Investment Tax Credit: Credit	(10) Investment Tax Credit: Amorti-zation	(11) Investment Tax Credit: Reserve
		$										
1.	1	1,000	18	0	0	1,000	80.00	31.07	0	100	1.79	0
2.	2	1,000	18	0	18	982	76.67	29.41	31.07	0	1.79	98.21
3.	3	1,000	18	0	36	964	73.33	27.73	60.48	0	1.79	96.42
4.	4	1,000	18	0	54	946	70.00	26.06	88.21	0	1.79	94.63
5.	5	1,000	18	0	72	928	66.67	24.39	114.27	0	1.79	92.84
6.	6	1,000	18	0	90	910	63.33	22.72	138.66	0	1.79	91.05
7.	7	1,000	18	0	108	892	60.00	21.05	161.38	0	1.79	89.26
8.	8	1,000	18	0	126	874	56.67	19.38	182.43	0	1.79	87.47
9.	9	1,000	18	0	144	856	53.33	17.71	201.81	0	1.79	85.68
10.	10	1,000	18	0	162	838	50.00	16.04	219.52	0	1.79	83.89
11.	11	1,000	18	0	180	820	46.67	14.37	235.56	0	1.79	82.10
12.	12	1,000	18	0	198	802	43.33	12.70	249.93	0	1.79	80.31
13.	13	1,000	18	0	216	784	40.00	11.03	262.63	0	1.79	78.52
14.	14	1,000	18	0	234	766	36.67	9.36	273.66	0	1.79	76.73
15.	15	1,000	18	0	252	748	33.33	7.68	283.02	0	1.79	74.94
16.	16	1,000	18	0	270	730	30.00	6.01	290.70	0	1.79	73.15
17.	17	1,000	18	0	288	712	26.67	4.35	296.71	0	1.79	71.36
18.	18	1,000	18	0	306	694	18.67	.34	301.06	0	1.79	69.57
19.	19	1,000	18	0	324	676	18.67	.34	301.40	0	1.79	67.78
20.	20	1,000	18	0	342	658	18.67	.34	301.74	0	1.79	65.99
21.	21	1,000	18	0	360	640	18.67	.34	302.08	0	1.79	64.20
22.	22	1,000	18	0	378	622	18.65	.30	302.42	0	1.79	62.41
23.	23	1,000	18	0	396	604	0	9.00	302.72	0	1.79	60.62
24.	24	1,000	18	0	414	586	0	9.00	293.72	0	1.79	58.83
25.	25	1,000	18	0	432	568	0	9.00	284.72	0	1.79	57.04
26.	26	1,000	18	0	450	550	0	9.00	275.72	0	1.79	55.25
27.	27	1,000	18	0	468	532	0	9.00	266.72	0	1.79	53.46
28.	28	1,000	18	0	486	514	0	9.00	257.72	0	1.79	51.67
29.	29	1,000	18	0	504	496	0	9.00	248.72	0	1.79	49.88
30.	30	1,000	18	0	522	478	0	9.00	239.72	0	1.79	48.09
31.	31	1,000	18	0	540	460	0	9.00	230.72	0	1.79	46.30
32.	32	1,000	18	0	558	442	0	9.00	221.72	0	1.79	44.51
33.	33	1,000	18	0	576	424	0	9.00	212.72	0	1.79	42.72
34.	34	1,000	18	0	594	406	0	9.00	203.72	0	1.79	40.93
35.	35	1,000	18	0	612	388	0	9.00	194.72	0	1.79	39.14
36.	36	1,000	18	0	630	370	0	9.00	185.72	0	1.79	37.35
37.	37	1,000	18	0	648	352	0	9.00	176.72	0	1.79	35.56
38.	38	1,000	18	0	666	334	0	9.00	167.72	0	1.79	33.77
39.	39	1,000	18	0	684	316	0	9.00	158.72	0	1.79	31.98
40.	40	1,000	18	0	702	298	0	9.00	149.72	0	1.79	30.19
41.	41	1,000	18	0	720	280	0	9.00	140.72	0	1.79	28.40
42.	42	1,000	18	0	738	262	0	9.00	131.72	0	1.79	26.61
43.	43	1,000	18	0	756	244	0	9.00	122.72	0	1.79	24.82
44.	44	1,000	18	0	774	226	0	9.00	113.72	0	1.79	23.03
45.	45	1,000	18	0	792	208	0	9.00	104.72	0	1.79	21.24
46.	46	1,000	18	0	810	190	0	9.00	95.72	0	1.79	19.45
47.	47	1,000	18	0	828	172	0	9.00	86.72	0	1.79	17.66
48.	48	1,000	18	0	846	154	0	9.00	77.72	0	1.79	15.87
49.	49	1,000	18	0	864	136	0	9.00	68.72	0	1.79	14.08
50.	50	1,000	18	0	882	118	0	9.00	59.72	0	1.79	12.29
51.	51	1,000	18	0	900	100	0	9.00	50.72	0	1.79	10.50
52.	52	1,000	18	0	918	82	0	9.00	41.72	0	1.79	8.71
53.	53	1,000	18	0	936	64	0	9.00	32.72	0	1.79	6.92
54.	54	1,000	18	0	954	46	0	9.00	23.72	0	1.79	5.13
55.	55	1,000	18	0	972	28	0	9.00	14.72	0	1.79	3.34
56.	56	1,000	10	0	990	10	0	5.72	5.72	0	1.55	1.55

[1] Average life of transmission plant = 56 years.

UTAH POWER AND LIGHT
CALCULATION OF PRESENT VALUE OF REVENUE REQUIREMENTS
RELATED TO INCREMENTAL $1,000 INVESTMENT
TRANSMISSION

		(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
										Present Value		
	Year	Mean Net Investment	Equity Return	Interest	Taxable Income	Investment Tax Credit	Income Tax	Ad Valorem Tax	Revenue Requirements	$1 @ 10.45%	Mean Annual Survivors	Revenue Requirement
						$						
1.	1	1,000.00	64.50	40.00	63.71	100.00	-18.19	13.00	246.59	.90539	905.39	223.26
2.	2	950.93	61.33	38.04	60.73	0	30.43	12.76	188.18	.81973	819.73	154.26
3.	3	903.52	58.28	36.14	57.92	0	29.03	12.53	179.92	.74217	742.17	133.53
4.	4	857.79	55.33	34.31	55.33	0	27.73	12.30	171.94	.67195	671.95	115.54
5.	5	813.73	52.49	32.55	52.97	0	26.55	12.06	164.25	.60838	608.38	99.93
6.	6	771.34	49.75	30.85	50.82	0	25.47	11.83	156.83	.55081	550.81	86.38
7.	7	730.62	47.12	29.22	48.88	0	24.49	11.60	149.69	.49870	498.70	74.65
8.	8	691.57	44.61	27.66	47.17	0	23.64	11.36	142.86	.45152	451.52	64.50
9.	9	654.19	42.20	26.17	45.70	0	22.90	11.13	136.32	.40880	408.80	55.73
10.	10	618.48	39.89	24.74	44.39	0	22.25	10.89	130.02	.37012	370.12	48.12
11.	11	584.44	37.70	23.38	43.32	0	21.71	10.66	124.03	.33510	335.10	41.56
12.	12	552.07	35.61	22.08	42.48	0	21.29	10.43	118.32	.30340	303.40	35.90
13.	13	521.37	33.63	20.85	41.84	0	20.97	10.19	112.88	.27469	274.69	34.25
14.	14	492.34	31.76	19.69	41.42	0	20.76	9.96	107.74	.24870	248.70	26.79
15.	15	464.98	29.99	18.60	41.20	0	20.65	9.72	102.85	.22517	225.17	23.16
16.	16	439.30	28.33	17.57	41.20	0	20.65	9.49	98.26	.20387	203.87	20.03
17.	17	415.29	26.79	16.61	41.46	0	20.78	9.26	94.00	.18458	184.58	17.35
18.	18	392.94	25.34	15.71	46.55	0	23.33	9.02	89.95	.16712	167.12	15.03
19.	19	372.27	24.01	14.89	43.89	0	22.00	8.79	86.24	.15130	151.30	13.05
20.	20	353.27	22.79	14.13	41.44	0	20.77	8.55	82.79	.13699	136.99	11.34
21.	21	335.94	21.67	13.44	39.19	0	19.64	8.32	79.62	.12403	124.03	9.88
22.	22	318.61	20.55	12.74	36.91	0	18.49	8.09	76.38	.11229	112.29	8.58
23.	23	301.28	19.43	12.05	53.41	0	26.77	7.85	73.31	.10167	101.67	7.45
24.	24	292.28	18.85	11.69	52.25	0	26.19	7.62	71.56	.09205	92.05	6.59
25.	25	283.28	18.27	11.33	51.08	0	25.60	7.38	69.79	.08334	83.34	5.82
26.	26	274.28	17.69	10.97	49.92	0	25.02	7.15	68.04	.07546	75.46	5.13
27.	27	265.28	17.11	10.61	48.76	0	24.44	6.92	66.29	.06832	68.32	4.53
28.	28	256.28	16.53	10.25	47.59	0	23.86	6.68	64.53	.06185	61.85	3.99
29.	29	247.28	15.95	9.89	46.43	0	23.27	6.45	62.77	.05600	56.00	3.52
30.	30	238.28	15.37	9.53	45.27	0	22.69	6.21	61.01	.05070	50.70	3.09
31.	31	229.28	14.79	9.17	44.11	0	22.11	5.98	59.26	.04591	45.91	2.72
32.	32	220.28	14.21	8.81	42.94	0	21.52	5.75	57.50	.04156	41.56	2.39
33.	33	211.28	13.63	8.45	41.78	0	20.94	5.51	55.74	.03763	37.63	2.10
34.	34	202.28	13.05	8.09	40.62	0	20.36	5.28	53.49	.03407	34.07	1.82
35.	35	193.28	12.47	7.73	39.45	0	19.77	5.04	52.22	.03085	30.85	1.61
36.	36	184.28	11.89	7.37	38.29	0	19.19	4.81	50.47	.02793	27.93	1.41
37.	37	175.28	11.31	7.01	37.13	0	18.61	4.58	48.72	.02529	25.29	1.23
38.	38	166.28	10.73	6.65	35.97	0	18.03	4.34	46.96	.02289	22.89	1.07
39.	39	157.28	10.14	6.29	34.78	0	17.43	4.11	45.18	.02073	20.73	.94
40.	40	148.28	9.56	5.93	33.62	0	16.85	3.87	43.42	.01877	18.77	.81
41.	41	139.28	8.98	5.57	32.46	0	16.27	3.64	41.67	.01699	16.99	.71
42.	42	130.28	8.40	5.21	31.30	0	15.69	3.41	39.92	.01538	15.38	.61
43.	43	121.28	7.82	4.85	30.13	0	15.10	3.17	38.15	.01393	13.93	.53
44.	44	112.28	7.24	4.49	28.97	0	14.52	2.94	36.40	.01261	12.61	.46
45.	45	103.28	6.66	4.13	27.81	0	13.94	2.70	34.64	.01142	11.42	.40
46.	46	94.28	6.08	3.77	26.64	0	13.35	2.47	32.88	.01034	10.34	.34
47.	47	85.28	5.50	3.41	25.48	0	12.77	2.24	31.13	.00936	9.36	.29
48.	48	76.28	4.92	3.05	24.32	0	12.19	2.00	29.37	.00847	8.47	.25
49.	49	67.28	4.34	2.69	23.16	0	11.61	1.77	27.62	.00767	7.67	.21
50.	50	58.28	3.76	2.33	21.99	0	11.02	1.53	25.85	.00695	6.95	.18
51.	51	49.28	3.18	1.97	20.83	0	10.44	1.30	24.10	.00629	6.29	.15
52.	52	40.28	2.60	1.61	19.68	0	9.86	1.07	22.35	.00569	5.69	.13
53.	53	31.28	2.02	1.25	18.50	0	9.27	.83	20.58	.00515	5.15	.11
54.	54	22.28	1.44	.89	17.34	0	8.69	.60	18.83	.00467	4.67	.09
55.	55	13.28	.86	.53	16.17	0	8.10	.36	17.06	.00423	4.23	.07
56.	56	4.28	.28	.17	6.03	0	3.02	.13	6.33	.00383	3.83	.02
57.	Total										9,532.81	1,373.59

58. Levelized revenue requirement relating to $1,000 incremental investment = 14.4% (Column 22, Line 26 ÷ Column 21, Line 26) x 100.

DERIVATION OF COLUMNS:

1. Incremental investment of $1,000 assumed.
2. Composite book (straight line) depreciation 1.79% x investment (col. 1). From FPC Form 1, composite of calendar year 1977.
3. No retirements assumed.
4. Cumulative of column 2.
5. Column 1 - column 4.
6. Sum of the years digits depreciation to year 16, straight line thereafter. From FPC Form 1, composite of calendar year 1977.
7. Tax rate (composite federal and state income tax rate supplied by UP&L (50.12%) x (col. 6 - col. 2).
8. Cumulative of column 7.
9. Current investment tax credit of 10% in the year investment is made.
10. Amortization of $100 over 56 years (100 ÷ 56).
11. Investment tax credit of $100 less annual amortization (col. 9).
12. Col. 1 - (col. 4 + col. 8).
13. Weighted cost of preferred debt (.85%) and common equity (5.6%) x col. 12.
14. Weighted cost of long-term debt (4.0%) x col. 12.
15. (Col. 2 - col. 6 - col. 10 + col. 13) ÷ (1 - effective tax rate).
16. Current investment tax credit of 10% in the year investment is made.
17. Effective tax rate (50.12%) x (col. 15 - col. 16).
18. Ad valorem tax rate (1.3%) x col. 5.
19. (Col. 2 + col. 7 - col. 10 + col. 13 + col. 14 + col. 16 + col. 17 + col. 18).
20. Present value of $1.00 discounted at future overall cost of capital (10.45%).
21. Col. 1 x col. 20.
22. Col. 19 x col. 20.

UTAH POWER AND LIGHT
CALCULATION OF PRESENT VALUE OF REVENUE REQUIREMENTS
RELATED TO INCREMENTAL $1,000 INVESTMENT
DISTRIBUTION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
										Investment Tax Credit		
	Year[1]	Mean Annual Survivors	Book Depreciation	Retirements	Book Depreciated Reserve	Mean Net Book Investment	Tax Depreciation	Deferred Income Tax	Deferred Tax Reserve	Credit	Amortization	Reserve
		$										
1.	1	1,000	25.00	0	0	1,000	80.00	27.55	0	100.00	2.50	0
2.	2	1,000	25.00	0	25	975	76.67	25.90	27.55	0	2.50	97.50
3.	3	1,000	25.00	0	50	950	73.33	24.22	53.45	0	2.50	95.00
4.	4	1,000	25.00	0	75	925	70.00	22.55	77.67	0	2.50	92.50
5.	5	1,000	25.00	0	100	900	66.67	20.89	100.22	0	2.50	90.00
6.	6	1,000	25.00	0	125	875	63.33	19.21	121.11	0	2.50	87.50
7.	7	1,000	25.00	0	150	850	60.00	17.54	140.32	0	2.50	85.00
8.	8	1,000	25.00	0	175	825	56.67	15.87	157.86	0	2.50	82.50
9.	9	1,000	25.00	0	200	800	53.33	14.20	173.73	0	2.50	80.00
10.	10	1,000	25.00	0	225	775	50.00	12.53	187.93	0	2.50	77.50
11.	11	1,000	25.00	0	250	750	46.67	10.86	200.46	0	2.50	75.00
12.	12	1,000	25.00	0	275	725	43.33	9.19	211.32	0	2.50	72.50
13.	13	1,000	25.00	0	300	700	40.00	7.52	220.51	0	2.50	70.00
14.	14	1,000	25.00	0	325	675	36.67	5.85	228.03	0	2.50	67.50
15.	15	1,000	25.00	0	350	650	33.33	4.17	233.88	0	2.50	65.00
16.	16	1,000	25.00	0	375	625	30.00	2.51	238.05	0	2.50	62.50
17.	17	1,000	25.00	0	400	600	30.00	2.51	240.56	0	2.50	60.00
18.	18	1,000	25.00	0	425	575	30.00	2.51	243.07	0	2.50	57.50
19.	19	1,000	25.00	0	450	550	30.00	2.51	245.58	0	2.50	55.00
20.	20	1,000	25.00	0	475	525	30.00	2.51	248.09	0	2.50	52.50
21.	21	1,000	25.00	0	500	500	0	-12.53	250.60	0	2.50	50.00
22.	22	1,000	25.00	0	525	475	0	-12.53	238.07	0	2.50	47.50
23.	23	1,000	25.00	0	550	450	0	-12.53	225.54	0	2.50	45.00
24.	24	1,000	25.00	0	575	425	0	-12.53	213.01	0	2.50	42.50
25.	25	1,000	25.00	0	600	400	0	-12.53	200.48	0	2.50	40.00
26.	26	1,000	25.00	0	625	375	0	-12.53	187.95	0	2.50	37.50
27.	27	1,000	25.00	0	650	350	0	-12.53	175.42	0	2.50	35.00
28.	28	1,000	25.00	0	675	325	0	-12.53	162.89	0	2.50	32.50
29.	29	1,000	25.00	0	700	300	0	-12.53	150.36	0	2.50	30.00
30.	30	1,000	25.00	0	725	275	0	-12.53	137.83	0	2.50	27.50
31.	31	1,000	25.00	0	750	250	0	-12.53	125.30	0	2.50	25.00
32.	32	1,000	25.00	0	775	225	0	-12.53	112.77	0	2.50	22.50
33.	33	1,000	25.00	0	800	200	0	-12.53	100.24	0	2.50	20.00
34.	34	1,000	25.00	0	825	175	0	-12.53	87.71	0	2.50	17.50
35.	35	1,000	25.00	0	850	150	0	-12.53	75.18	0	2.50	15.00
36.	36	1,000	25.00	0	875	125	0	-12.53	62.65	0	2.50	12.50
37.	37	1,000	25.00	0	900	100	0	-12.53	50.12	0	2.50	10.00
38.	38	1,000	25.00	0	925	75	0	-12.53	37.59	0	2.50	7.50
39.	39	1,000	25.00	0	950	50	0	-12.53	25.06	0	2.50	5.00
40.	40	1,000	25.00	0	975	25	0	-12.53	12.53	0	2.50	2.50

[1] Average life of distribution plant = 40 years.

UTAH POWER AND LIGHT
CALCULATION OF PRESENT VALUE OF REVENUE REQUIREMENTS
RELATED TO INCREMENTAL $1,000 INVESTMENT
DISTRIBUTION

	Year		(12) Mean Net Investment	(13) Equity Return	(14) Interest	(15) Taxable Income	(16) Investment Tax Credit	(17) Income Tax	(18) Ad Valorem Tax	(19) Revenue Requirements	(20) Present Value $1 @ 10.45%	(21) Present Value Mean Annual Survivors	(22) Present Value Revenue Requirement
			$										
1.	1		1,000.00	64.50	40.00	69.27	100.00	-15.40	13.00	252.15	.90539	905.39	228.29
2.	2		947.45	61.11	37.90	65.84	0	33.00	12.68	193.09	.81973	819.73	158.28
3.	3		896.55	57.83	35.86	62.59	0	31.37	12.35	184.13	.74217	742.17	136.66
4.	4		847.33	54.65	33.89	59.54	0	29.84	12.03	175.46	.67195	671.95	117.90
5.	5		799.78	51.59	31.99	56.75	0	28.44	11.70	167.11	.60838	608.38	101.67
6.	6		753.89	48.63	30.16	54.14	0	27.13	11.38	159.01	.55081	550.81	87.58
7.	7		709.68	45.77	28.39	51.74	0	25.93	11.05	151.18	.49870	498.70	75.39
8.	8		667.14	43.03	26.69	49.58	0	24.85	10.73	143.67	.45152	451.52	64.87
9.	9		626.27	40.39	25.05	47.63	0	23.87	10.40	136.41	.40880	408.80	55.76
10.	10		587.07	37.87	23.48	45.91	0	23.01	10.08	129.47	.37012	370.12	47.92
11.	11		549.54	35.45	21.98	44.39	0	22.25	9.75	122.79	.33510	335.10	41.15
12.	12		513.68	33.13	20.55	43.08	0	21.59	9.43	116.39	.30340	303.40	35.31
13.	13		479.49	30.93	19.18	42.00	0	21.05	9.10	110.28	.27469	274.69	30.27
14.	14		446.97	28.83	17.88	41.12	0	20.61	8.78	104.45	.24870	248.70	25.98
15.	15		416.12	26.84	16.64	40.46	0	20.28	8.45	98.88	.22517	225.17	22.26
16.	16		386.95	24.96	15.48	40.04	0	20.07	8.13	93.65	.20387	203.87	19.09
17.	17		359.44	23.18	14.38	36.47	0	18.28	7.80	88.65	.18458	184.58	16.36
18.	18		331.93	21.41	13.28	32.92	0	16.50	7.48	61.18	.16712	167.12	10.22
19.	19		304.42	19.64	12.18	29.37	0	14.72	7.15	78.70	.15130	151.30	11.90
20.	20		276.91	17.86	11.08	25.80	0	12.93	6.83	73.71	.13699	136.99	10.10
21.	21		249.40	16.09	9.98	52.24	0	26.18	6.50	68.72	.12403	124.03	8.52
22.	22		236.93	15.28	9.48	50.62	0	25.37	6.18	66.28	.11229	112.29	7.44
23.	23		224.46	14.48	8.98	49.02	0	24.57	5.85	63.85	.10167	101.67	6.49
24.	24		211.99	13.67	8.48	47.39	0	23.75	5.53	61.40	.09205	92.05	5.65
25.	25		199.52	12.87	7.98	45.79	0	22.95	5.20	58.97	.08334	83.34	4.91
26.	26		187.05	12.06	7.48	44.17	0	22.14	4.88	56.53	.07546	75.46	4.27
27.	27		174.58	11.26	6.98	42.57	0	21.34	4.55	54.10	.06832	68.32	3.70
28.	28		162.11	10.46	6.48	40.96	0	20.53	4.23	51.67	.06185	61.85	3.19
29.	29		149.64	9.65	5.98	39.33	0	19.71	3.90	49.21	.05600	56.00	2.76
30.	30		137.17	8.85	5.49	37.73	0	18.91	3.58	46.80	.05070	50.70	2.67
31.	31		124.70	8.04	4.99		0	18.10	3.25	44.35	.04591	45.91	2.04
32.	32		112.23	7.24	4.49	34.50	0	17.29	2.93	41.92	.04156	41.56	1.74
33.	33		99.76	6.43	3.99	32.88	0	16.48	2.60	39.47	.03763	37.63	1.49
34.	34		87.29	5.63	3.49	31.28	0	15.68	2.28	37.05	.03407	34.07	1.26
35.	35		74.82	4.83	2.99	29.67	0	14.87	1.98	34.64	.03085	30.85	1.07
36.	36		62.35	4.02	2.49	28.05	0	14.06	1.63	32.17	.02793	27.93	.89
37.	37		49.88	3.22	2.00	26.44	0	13.25	1.30	29.74	.02529	25.29	.75
38.	38		37.41	2.41	1.50	24.82	0	12.44	.98	27.30	.02289	22.89	.62
39.	39		24.94	1.61	1.00	23.22	0	11.64	.65	24.87	.02073	20.73	.52
40.	40		12.47	.80	.50	21.59	0	10.82	.33	22.42	.01877	18.77	.42
41.	41	Total										9,389.83	1,357.36

42. Levelized revenue requirement relating to $1,000 incremental investment = 14.456% (Column 22, line 26 ÷ column 21, line 26) x 100.

DERIVATION OF COLUMNS:

1. Incremental investment of $1,000 assumed.
2. Composite book (straight line) depreciation 2.5% x investment (col. 1). From FPC Form 1, composite of calendar year 1977.
3. No retirements assumed.
4. Cumulative of column 2.
5. Column 1 - column 4.
6. Sum of the years digits depreciation to year 16, straight line thereafter. From FPC Form 1, composite of calendar year 1977.
7. Tax rate (composite federal and state income tax rate supplied by UP&L (50.12%) x (col. 6 - col. 2).
8. Cumulative of column 7.
9. Current investment tax credit of 10% in the year investment is made.
10. Amortization of $100 over 40 years (100 ÷ 40).
11. Investment tax credit of $100 less annual amortization (col. 9).
12. Col. 1 - (col. 4 + col. 8).
13. Weighted cost of preferred debt (.85%) and common equity (5.6%) x col. 12.
14. Weighted cost of long-term debt (4.0%) x col. 12.
15. (Col. 2 - col. 6 - col. 10 + col. 13) ÷ (1 - effective tax rate).
16. Current investment tax credit of 10% in the year investment is made.
17. Effective tax rate (50.12%) x (col. 15 - col. 16).
18. Ad valorem tax rate (1.3%) x col. 5.
19. (Col. 2 + col. 7 - col. 10 + col. 13 + col. 14 + col. 16 + col. 17 + col. 18).
20. Present value of $1.00 discounted at future overall cost of capital (10.45%).
21. Col. 1 x col. 20.
22. Col. 19 x col. 20.

UTAH POWER AND LIGHT
DERIVATION OF ANNUAL ECONOMIC CARRYING CHARGE
RELATED TO CAPITAL INVESTMENT

GENERATION

1.	Present Value of Revenue Requirements Related to Incremental $1,000 Investment[1]	$1,351.76
2.	Annual Charge Expressed in Constant Dollars Related to Incremental $1,000 Investment[2]	$ 120.84
3.	Annual Economic Charge Related to Marginal Investment (line 2 ÷ $1,000 x 100)	12.08%

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[1] Schedule 2.1, line 37, column 22.

[2] $$AC_t = K\,(r-j)\,(1+j)^{t-1}\left\{\frac{1}{1-\left(\frac{1+j}{1+r}\right)^n}\right\}$$

where:

AC_t = Annual charge in year t
t = Year = 1
K = Present value = $1,351.76 (schedule 2.1.1, col. 22, line 37)
r = Overall cost of capital = 10.45%
j = Inflation net of technical progress = 2.0%
n = Service life = 36.5 years

UTAH POWER AND LIGHT
DERIVATION OF ANNUAL ECONOMIC CARRYING CHARGE RELATED TO CAPITAL INVESTMENT

TRANSMISSION

1.	Present Value of Revenue Requirements Related to Incremental \$1,000 Investment[1]	\$1,373.59
2.	Annual Charge Expressed in Constant Dollars Related to Incremental \$1,000 Investment[1]	\$ 117.47
3.	Annual Economic Charge Related to Marginal Investment (line 2 ÷ \$1,000 x 100)	11.75%

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[1] Table 2.1.2, line 57, column 22.

[2] $$AC_t = K\ (r-j)\ (1 + j)^{t-1} \left\{ \frac{1}{1 - \left(\frac{1+j}{1+r}\right)^n} \right\}$$

where:

AC_t = Annual charge in year t
t = Year = 1
K = Present value = \$1,373.59 (schedule 2.1.2, col. 22, line 57)
r = Overall cost of capital = 10.45%
j = Inflation net of technical progress = 2.0%
n = Service life = 55.6 years

UTAH POWER AND LIGHT
DERIVATION OF ANNUAL ECONOMIC CARRYING CHARGE RELATED TO CAPITAL INVESTMENT

DISTRIBUTION

1.	Present Value of Revenue Requirements Related to Incremental $1,000 Investment[1]	$1,357.36
2.	Annual Charge Expressed in Constant Dollars Related to Incremental $1,000 Investment[2]	$ 119.65
3.	Annual Economic Charge Related to Marginal Investment (line 2 ÷ $1,000 x 100)	11.965%

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[1] Schedule 2.3.2, line 41, column 22.

[2] $$AC_t = K\ (r-j)\ (1 + j)^{t-1} \left\{ \frac{1}{1 - \left(\frac{1+j}{1+r}\right)^n} \right\}$$

where:

AC_t = Annual charge in year t
t = Year = 1
K = Present value = $1,357.36 (schedule 2.1.3, col. 22, line 41)
r = Overall cost of capital = 10.45%
j = Inflation net of technical progress = 2.0%
n = Service life = 40 years

UTAH POWER AND LIGHT
COMPUTATION OF LOADING FACTORS FOR A&G EXPENSES AND SECURITY AND UNEMPLOYMENT INSURANCE TAXES

	FPC Acct. No.	Account	Amount ($000)
		Administrative and General Expenses and Social Security and Unemployment Taxes, 1977	
		Applicable to Managerial Effort	
1.	920	Administrative and General Salaries	$ 10,391
2.	921	Office Supplies and Expenses	2,295
3.	922	Administrative Expense Transferred-Credit	(3,814)
4.	930	Miscellaneous General Expense	2,810
5.	931	Rents	351
6.		Total	12,033
7.		Applicable to Energy-Related O&M Expenses[1]	9,065
8.		Applicable to Other O&M Expenses (line 6 - line 7)	2,968
		Applicable to Labor	
9.	925	Injuries and Damages	765
10.	926	Employee Pensions and Benefits	5,486
11.	929	Duplicate Charges-Credit	(3)
12.	408.1	Social Security and Unemployment Insurance Taxes	3,167
13.		Total	9,415
14.		Applicable to Energy-Related O&M Expenses[2]	2,892
15.		Applicable to Other O&M Expenses (line 13 - line 14)	6,523
		Applicable to Plant	
16.	923	Outside Services Employed	716
17.	924	Property Insurance	932
18.	927	Franchise Requirements	3
19.	928	Regulatory Commission Expenses	152
20.	932	Maintenance of General Plant	888
21.		Total	2,691
22.		Total A&G Expenses and Social Security and Unemployment Insurance Taxes (line 6 + line 13 + line 21)	24,139
23.		Total A&G Expenses (line 22 - line 12)	20,972

[1] Total A&G expenses applicable to managerial effort have been allocated to energy-related O&M expenses on the basis of the ratio of total energy-related O&M production expenses (line 28) to total O&M expenses excluding A&G expenses (line 25).

[2] Total A&G expenses applicable to labor have been allocated to energy-related O&M expenses on the basis of the ratio of energy-related O&M production expenses excluding fuel and purchased power (line 27) to total O&M expenses excluding fuel and purchased power and A&G expenses (line 25 - line 26).

	FPC Acct. No.	Account	Amount
24.		Total Operation and Maintenance Expenses, 1977	169,256
25.		Total O&M Expenses Excluding A&G Expenses (line 24 - line 23)	148,284
26.		Fuel and Purchased Power	95,492
27.		Energy-Related Production O&M Expenses Excluding Fuel and Purchased Power[3]	16,217
28.		Total Energy-Related O&M Expenses (line 26 + line 27)	111,709
29.		Labor-Related O&M Expenses (line 25 + line 28)	36,575
30.		A&G Loading Factor Applicable to Labor-Related O&M Expenses (line 8 + line 15 ÷ line 29)	25.95%
31.		Total Gross Plant, Dec. 31, 1977	1,200,314
32.		A&G Loading Factor Applicable to Plant (line 21 ÷ line 31)	0.22%
33.		Electricity Generated and Purchased (GWH)	12,409
34.		Energy-Related A&G Expenses (Mills/kWh) (line 7 + line 14 ÷ line 33)	.9636

[3] Energy-related production expenses were derived by the allocation of production O&M expenses, by account, to energy and demand using factors developed by analysis of 1977 Cost of Service Study.

UTAH POWER AND LIGHT
DEVELOPMENT OF CAPACITY ADJUSTMENT FACTORS

	(1)	(2)	(3)	(4)	(5)
	Expanded Capacity Adjustment Factors by Voltage Level				
	Secondary	Primary	46-96 kV	138 kV	Generation
Demand Losses at Peak					
1. Secondary Sales	1.000000	1.063501	1.093665	1.149195	1.183790
2. Primary Sales		--	1.028363	1.080577	1.113107
3. 46-69 kV		--	--	1.050774	1.082407
4. 138 kV		--	--	--	1.030104

SOURCE: Supplied by UP&L.

NOTE: Capacity losses vary from peak to off-peak; however, NERA uses peak losses for peak and off-peak periods.

UTAH POWER AND LIGHT
DEVELOPMENT OF ENERGY ADJUSTMENT FACTORS

	(1)	(2)	(3)	(4)	(5)
	Expanded Energy Adjustment Factors by Voltage Level				
	Secondary	Primary	46-69 kV	138 kV	Generation
1. Secondary Sales	1.000000	1.023633	1.050079	1.100477	1.130040
2. Primary Sales	--	--	1.025835	1.075069	1.103950
3. 46-69 kV	--	--	--	1.047994	1.076148
4. 138 kV	--	--	--	--	1.026864

SOURCE: Provided by UP&L.

NOTE: Energy losses vary from peak to off-peak periods; however, NERA uses peak period losses for both peak and off-peak periods.

UTAH POWER AND LIGHT
COMPUTATION OF MARGINAL UNIT COST
DEMAND-RELATED GENERATION

1.	Long-Run Unit Investment[1]	$ 210.00
2.	With General Plant Loading (line 1 x 1.052)[2]	220.92
3.	Annual Carrying Charge Related to Capital Investment[3]	12.08%
4.	Administrative and General Loading[4]	0.22%
5.	Total (line 3 + line 4)	12.30%
6.	Annualized Costs (line 2 x line 5)	$ 27.17
7.	Demand-Related Operation and Maintenance Expenses[5]	
8.	With Administrative and General Loading (line 7 x 1.26)[6]	3.15
	Working Capital	
9.	Materials and Supplies (line 2 x .031)[7]	6.85
10.	Prepayments (line 2 x .001)[6]	.22
11.	Demand-Related Cash Working Capital (line 8 x 1/8)	.39
12.	Total Working Capital (line 9 + line 10 + line 11)	7.46
13.	Revenue Requirement for Working Capital (line 12 x 1.1701)[8]	8.73
14.	Total Demand-Related Costs (line 6 + line 8 + line 13)	39.05
15.	Total Annual Marginal Costs (Rounded)	$ 39.00

[1] Cost of a combustion turbine adjusted for planned reserve margin. Long-run investment of gas turbine $210/kW, estimated O&M expenses provided by consultant.

[2] Based on an analysis of the historic relationship between additions to general plant and the additions to electric utility plant in service less general plant additions.

[3] See schedule 2.2.1, line 3.

[4] See schedule 3.0, line 32.

[5] CH2M HILL estimate.

[6] See schedule 3.0, line 30.

[7] Based on historical relationships between M&S and gross investment and prepayments and gross investment.

[8] Marginal cost of capital. Includes overall return (future overall cost of capital 1985), and Federal and state income tax as a percentage of working capital.

Schedule 5.1.4

UTAH POWER AND LIGHT
MARGINAL DEMAND-RELATED UNIT COST BY
COSTING PERIOD GENERATION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		System Segment					Unit Cost				
	Costing Period	Secondary	Primary	46-69 kV	138 kV	Allocation Factor[1]	Secondary (line 1 x line 5 ÷ line 10)	Primary (line 2 x line 5 ÷ line 10)	46-69 kV (line 3 x line 5 ÷ line 10)	138 kV	CF[2]
		(dollars per kW)					(dollars per kW)				
	Peak Season										
1.	Generation	46.17[3]	43.41[3]	42.21[3]	40.17[3]	.60	30.68	28.84	28.05	26.73	.903
	Off-Peak Season										
2.	Generation	46.17[3]	43.41[3]	42.21[3]	40.17[3]	.40	19.54	18.37	17.87	17.00	.945

[1] Assumed 60/40 since actual data not available.

[2] Coincidence factor (CF) is the average of monthly peak demands in period ÷ peak demand for period.

[3] Generation marginal unit cost from Schedule 5.1.3 has been adjusted by capacity adjustment factor from Schedule 4.1 to account for electric losses at time of peak between generation, transmission facilities, primary, and secondary voltage delivery level.

Schedule 5.2.1

UTAH POWER AND LIGHT
DERIVATION OF MARGINAL INVESTMENT IN TRANSMISSION FACILITIES

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
			Additions Related to:*						
	Year	Gross Additions to Transmission Plant	Remote Generation	Pool Requirements	Load Added After Period	Load-Related Additions to Transmission Plant col. 1 - (col. 2 + col. 3 + col. 4)	Inflation Factor[1]	Additions to Transmission Plant (line 5 ÷ line 6)	Additions to System Peak Demand (MW)
		$000 1978						$000 1978	
1.	1974	40,247	-	-	-	40,247	.763	52,748	--
2.	1975	15,489	-	-	-	15,489	.816	18,982	173
3.	1976	50,551	-	-	-	50,551	.873	57,905	43
4.	1977	93,034	-	-	-	93,034	.935	99,502	108
5.	1978	75,049	-	-	-	75,049	1.000	75,049	150
6.	1979	24,718	-	-	-	24,718	1.070	23,101	157
7.	1980	112,742	-	-	-	112,742	1.145	98,465	110
8.	1981	37,770	-	-	-	37,770	1.225	30,833	92
9.	1982	71,860	-	-	-	71,860	1.311	54,813	-
10.	Total Additions	521,460[4]						403,837[4]	833

11. Marginal Investment in Transmission Facilities per kW. 484.80
(Column 7, line 11 ÷ column 8, line 11)

[1] Inflation factor post 1977 estimated at 7 percent per year with 1978 as base year.

[2] Expenditures made in years prior to 1977 relating to peak growth in period 1978 to 1983.

[3] Expenditures in 1977 and 1978 are related to growth in the period 1979 to 1983 and therefore additions to peak in these years are not applicable to period being listed.

[4] Total does not include 1974 and 1982.

* Data not provided.

SOURCES: 1974-1977 FPC Form 1.
1978-1983 supplied by UP&L.

UTAH POWER AND LIGHT
ANNUAL TRANSMISSION EXPENSE PER KILOWATT OF SYSTEM PEAK DEMAND

		(1)	(2)	(3)	(4)	(5)
	Year	Transmission Operations & Maintenance Expense[1] (thousand dollars)	Electric Labor Cost Index (1978=100)	Transmission O&M Expenses (Ln1 ÷ Ln2) ($000)	System Peak Demand (MW)	Expense per kW of System Peak Demand (Ln3 ÷ Ln4)
1.	1974	2,130	.69	3,087	1626	1.90
2.	1975	2,948	.79	3,732	1799	2.07
3.	1976	3,063	.87	3,521	1842	1.91
4.	1977	3,528	.92	3,835	1950	1.97
5.	1978		1.00	*	--	--
6.	Estimated Transmission O&M Expense (excluding account 565) per kilowatt for the planning period (1979-1985) in 1978 dollars					1.96[2]

[1] From FPC form 1, excludes account 565.

[2] Average of line 4, 1974-1978.

* Data not provided.

UTAH POWER AND LIGHT
COMPUTATION OF MARGINAL UNIT COST
DEMAND-RELATED TRANSMISSION

		$/kW
1.	Long-Run Unit Investment[1]	$485.00
2.	With General Plant Loading (line 1 x 1.052)[2]	510.01
3.	Annual Carrying Charge Related to Capital Investment[3]	11.75%
4.	Administrative and General Loading[4]	0.22%
5.	Total (line 3 + line 4)	11.97%
6.	Annualized Costs (line 2 x line 5)	$ 61.05
	Transmission of Electricity by Others	
7.	Payments in Lieu of Capital Expenditures (Net Wheeling Cost/kW)	$ 6.76
8.	Demand-Related Operation and Maintenance Expenses[5]	1.96
9.	With Administrative and General Loading (line 8 x 1.26)[6]	2.47
10.	Demand-Related Costs (line 6 + line 7 + line 9)	70.28
	<u>Working Capital</u>	
11.	Materials and Supplies (line 2 x .031)[7]	$ 15.81
12.	Prepayments (line 2 x .001)[7]	.51
13.	Demand-Related Cash Working Capital (line 7 + line 9 x 1/8)	1.15
14.	Total Working Capital (line 11 + line 12 + line 13)	17.47
15.	Revenue Requirement for Working Capital (line 14 x 1.1701)[8]	20.44
16.	Total Demand-Related Costs (line 10 + line 15)	90.72
17.	Total Annual Marginal Costs (Rounded)	$ 91.00

[1] Schedule 5.2.1, line 11.

[2] Based on an analysis of the historic relationship between additions to general plant and the additions to utility plant in service less general plant additions.

[3] Schedule 2.2.2, line 3.

[4] Schedule 3.0, line 32.

[5] Schedule 5.2.2, line 6.

[6] Schedule 3.0, line 30.

[7] Based on the historical relationships between materials and supplies and gross investment and prepayments and gross investment.

[8] Marginal cost of capital. Includes overall return (future overall cost of capital in 1985) and Federal and state income tax as a percentage of working capital.

UTAH POWER AND LIGHT
MARGINAL DEMAND-RELATED UNIT COST BY COSTING PERIOD
TRANSMISSION

Schedule 5.2.4

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		System Segment					Unit Cost				
	Costing Period	Secondary	Primary	46-69 kV	138 kV	Allocation Factor[1]	Secondary (line 1 x line 5 ÷ line 10)	Primary (line 2 x line 5 ÷ line 10)	46-69 kV (line 3 x line 5 ÷ line 10)	138 kV	CF[2]
		(dollars per kW)					(dollars per kW)				
	Peak										
1.	Transmission	104.58[3]	98.33[3]	95.62[3]	91.00[3]	.60	69.49	65.34	65.53	60.47	.903
	Off Peak										
2.	Transmission	104.58[3]	98.33[3]	95.62[3]	91.00[3]	.40	44.27	41.62	40.47	38.52	.945

[1] Assumed 60/40 since actual data not available.

[2] Coincidence Factor (CF) is the average of the peak demands in period ÷ peak demand for period.

[3] Transmission marginal unit from 5.2.1 have been adjusted by capacity adjustment factor from Schedule 4.1 to account for electric losses at time of peak between transmission facilities and primary and secondary voltage delivery level.

UTAH POWER AND LIGHT
DERIVATION OF MINIMUM SYSTEM COST PER CUSTOMER

		(1) Labor	(2) Material	(3) Total
		---------(1978 dollars)---------		
	PRIMARY SERVICE:			
1.	Set Pole (45-foot)	185.38	311.43	496.81
2.	Frame Pole[1]	76.27	145.33	221.60
3.	Cost Per Pole (line 1 + line 2)			718.41
4.	Cost Per Customer (line 3 ÷ 2.78)[2]			258.42
5.	Meter		24.53	24.53
6.	Total Cost Per Primary Service Customer (line 4 + line 5)			282.95
	SECONDARY SERVICE:			
7.	Set Pole (45-foot)	185.38	311.43	496.81
8.	Frame Pole[1]	190.67	145.33	336.00
9.	Secondary Rack		19.28	19.28
10.	Transformer	62.92	-0-	62.92
11.	Cost Per Pole (column 3, lines 7 + 8 + 9 + 10)			915.01
12.	Cost Per Customer (line 11 ÷ 2.78)[2]			329.14
13.	Service Drop		13.59	13.59
14.	Meter		24.53	24.53
15.	Total Cost Per Secondary Service Customer (line 12 + line 13 + line 14)			367.26

[1] Includes labor for conductor installation.

[2] Assumes 2.78 customers per pole.

SOURCE: Data from Seattle City Light, adjusted for regional price differential.

UTAH POWER AND LIGHT
DISTRIBUTION O&M EXPENSE PER CUSTOMER

	Year	Total Dist. O&M Expense (thousand $)[1]	Electric Labor Cost Index (1978=100)	Total Dist. O&M Expenses (Ln1 ÷ Ln2) (thousand 1978 dollars)	Customer-Related Expenses (Ln3 x 60%) (thousand 1978 dollars)	Average Number of Customers[2]	Customer-Related Expense per Customer (Ln4 ÷ Ln5)
1.	1974	7,670,222	.69	11,116,264	6,669,758	327,502	20.37
2.	1975	9,766,230	.79	12,362,316	7,417,390	341,122	21.74
3.	1976	11,334,062	.87	13,027,657	7,816,594	357,122	21.89
4.	1977	12,946,341	.92	14,072,110	8,443,266	374,807	22.53
5.	1978	*	1.00	--	--	--	--

6. Estimated Distribution O&M Expense for Planning Period[3] (1978 dollars) = 23.00

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[1] Total distribution expenses less street lighting and pro rata portion of 580, 588, 589, 590, and 598 FPC Form 1.

[2] Average number of customers except street lighting and resale (Form 1).

[3] Estimated by escalating 1977 average compound growth rate 1974-1977, assumed because the trend appears to be increasing distribution costs.

* Data not provided.

UTAH POWER AND LIGHT
COMPUTATION OF MARGINAL UNIT COST
CUSTOMER RELATED

Schedule 5.3.3

		(1) Residential	(2) Commercial	(3) Industrial Firm	(4) Irrigation	(5) Street Lighting
1.	Long-Run Unit Investment ($)	367.26[1]	367.26[1]	282.95[2]	282.95[2]	282.95[2]
2.	With General Plant Loading (line 1 x 1.052)[3] ($)	386.36	386.36	297.66	297.66	297.66
3.	Annual Economic Charge Related to Capital Investment[4] (%)	11.965	11.965	11.965	11.965	11.965
4.	Administrative and General Loading[5] (%)	.22	.22	.22	.22	.22
5.	Total (line 3 + line 4) (%)	12.19	12.19	12.19	12.19	12.19
6.	Annualized Costs (line 2 x line 5) ($)	47.10	47.10	36.28	36.28	36.28
7.	Customer-Related Distribution O&M Expenses[6] ($)	23.00	23.00	23.00	23.00	23.00
8.	With Administrative and General Loading (line 7 x 1.26)[7] ($)	28.98	28.98	28.98	28.98	28.98
9.	Customer Accounts Expenses[8] ($)	20.43	40.86	102.15	40.86	10.22
10.	Customer Sales Expenses[9] ($)	4.32	8.64	21.60	8.64	2.16
11.	Total Customer Accounts and Service Expenses (line 9 + line 10) ($)	24.75	49.50	123.75	49.50	12.38
12.	With Administrative and General Loading (line 11 x 1.26)[7] ($)	31.19	62.37	155.93	62.37	15.60
13.	Total Customer-Related Costs (line 6 + line 8 + line 12) ($)	107.27	138.45	221.19	127.63	80.86
	Working Capital					
14.	Materials and Supplies (line 2 x .031)[10] ($)	11.98	11.98	9.23	9.23	9.23
15.	Prepayments (line 2 x .001)[10] ($)	.39	.39	.30	.30	.30
16.	Customer-Related Cash Working Capital (line 8 + line 12 x 1/8) ($)	7.52	11.42	23.11	11.42	5.57
17.	Total Working Capital (line 14 + line 15 + line 16) ($)	19.89	23.79	32.64	20.95	15.10
18.	Revenue Requirement for Working Capital (line 17 x 1.1701)[11] ($)	23.27	27.84	38.19	24.51	17.67
19.	Total Customer-Related Costs (line 13 + line 18) ($)	130.54	166.29	259.38	152.14	98.53
20.	Total Marginal Costs (Rounded) ($)	131.00	166.00	259.00	152.00	98.00

1 Schedule 5.3.1, line 15.

2 Schedule 5.3.1, line 6.

3 Based on an analysis of the historic relationship between additions to general plant and additions to total electric plant in service less general plant additions.

4 Schedule 2.2.3.

5 Schedule 3.0, line 32.

6 Schedule 5.3.2, line 7, column 6.

7 Schedule 3.0, line 30.

8 Schedule 6.1.1, col. 3.

9 Schedule 6.2, line 8.

10 Based on an analysis of the historic relationship between materials and supplies and gross investment and prepayments and gross investment. See Schedule 5.1.3, footnote 7.

11 Marginal cost of capital. Includes overall return (overall cost of capital 1985), and Federal and state income tax as a percentage of working capital.

UTAH POWER AND LIGHT
DERIVATION OF MARGINAL DEMAND-RELATED DISTRIBUTION INVESTMENT

Schedule 5.4.1

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Addition to Distribution Plant ($000)[1]	Inflation Factor	Addition to Distribution Plant[2]	Add. for Rplcmt. of Ext. Facil.	Addition for Replacement (col. 4 x col. 1)	Cust. at Year End[3]	Cust. Rltd. Additions (Line 6 x $367 ÷ 1,000)	Dmd. Rltd. Additions (Line 3 - line 5 - line 7)	Add to Dist. Sys. Demand (MW)[5]	Marginal Demand-Related Dist. Investment per Added kW of Dist. Demand (Line 8 ÷ line 9)
				($000 1978)	($000 1978)	($000 1978)		($000 1978)	($000 1978)		($000 1978)
1.	1978	26,875	1.000	26,875	-	-	17,241	6,327	20,548	150	136.99
2.	1979	30,355	1.070	28,369	-	-	18,034	6,618	21,751	157	138.54
3.	1980	34,210	1.145	29,878	-	-	18,864	6,923	22,955	110	208.68
4.	1981	38,810	1.225	31,682	-	-	19,732	7,242	24,440	92	265.65
5.	1982	44,015	1.311	33,574	-	-	20,639	7,575	25,999	*	-
6.	1983	49,945	1.403	35,599	-	-	21,588	7,923	27,676	*	-
7.											Average = 187.47

[1] Projected additions to distribution plant 1978-1983. Provided by UP&L.

[2] Projected additions for replacement of existing facilities 1978-1983. Provided by UP&L.

[3] New customers from 1978-1983. Provided by UP&L.

[4] Schedule 5.3.1, line 15.

[5] Additional increase in distribution system demand in MW from 1978-1983.

* Data not provided.

UTAH POWER AND LIGHT
ANNUAL DISTRIBUTION O&M EXPENSE PER KW OF PEAK DISTRIBUTION DEMAND

	Year	(1) Total Dist. O&M Expns. ($000)[1]	(2) Electric Labor Cost Index (1978=100)	(3) Total Dist. O&M Expns. (Col. 1 ÷ Col. 2)	(4) Dem.-Rltd. Expenses (Col. 3 x 40%)	(5) Dist. Peak Demand[2] (MW)	(6) Dem.-Rltd. Exp. per kW of Dist. Peak Demand (Col. 4 ÷ Col. 5)
				-(thousand 1978 dollars)-			
1.	1974	8,468	.69	12,272	4,909	1,626	3.02
2.	1975	10,693	.79	13,535	5,414	1,799	3.01
3.	1976	12,194	.87	14,016	5,606	1,842	3.04
4.	1977	13,883	.92	15,090	6,036	1,950	3.10
5.	1978	*	1.00	--	--	--	--
6.	Estimated Distribution O&M Expense for Planning Period[3] (1978 dollars) =						3.10

[1] Total distribution expenses less street lighting and pro rata portion of 580, 588, 589, 590, and 598 FPC Form 1.

[2] System Peak Demand (FPC Form 12).

[3] Assumed 1978 expense; trend appears to be toward increasing costs.

* Data not provided.

UTAH POWER AND LIGHT
COMPUTATION OF MARGINAL UNIT COST
DEMAND-RELATED DISTRIBUTION

		$/kW
1.	Long-Run Unit Investment[1]	$ 187.00
2.	With General Plant Loading (line 1 x 1.052)[2]	196.72
3.	Annual Carrying Charge Related to Capital Investment[3]	11.965
4.	Administrative and General Loading[4]	0.22%
5.	Total (line 3 + line 4)	12.19
6.	Annualized Costs (line 2 x line 5)	23.98
7.	Demand-Related Operation and Maintenance Expenses[5]	3.10
8.	With Administrative and General Loading (line 8 x 1.26)[6]	3.91
9.	Demand-Related Costs (line 6 + line 8)	27.89
	Working Capital	
10.	Materials and Supplies (line 2 x .031)[7]	6.10
11.	Prepayments (line 2 x .001)[7]	.20
12.	Demand-Related Cash Working Capital (line 8 x 1/8)	.49
13.	Total Working Capital (line 10 + line 11 + line 12)	6.79
14.	Revenue Requirement for Working Capital (line 13 x 1.170)[8]	7.94
15.	Total Demand-Related Costs (line 9 + line 14)	35.83
16.	Total Annual Marginal Costs (Rounded)	36.00

[1] Schedule 5.4.1, line 7.

[2] Based on an analysis of the historic relationship between additions to general plant and the additions to utility plant in service less general plant additions.

[3] Schedule 2.2.3.

[4] Schedule 3.0, line 32.

[5] See schedule 5.4.2, line 7.

[6] Schedule 3.0, line 30.

[7] Based on the historic relationships between materials and supplies and gross investment and prepayments and gross investment.

[8] Marginal cost of capital. Includes overall return (overall cost of capital in 1985), and Federal and state income tax as a percentage of working capital.

UTAH POWER AND LIGHT
MARGINAL DEMAND-RELATED UNIT COSTING PERIOD
DISTRIBUTION

		(1)	(2)	(3)	(4)	(5)	(6)
					Unit Cost		
		System Segment			Secondary (Line 1 x Line 3 ÷ Line 7)	Primary (Line 2 x Line 3 ÷ Line 7)	
	Costing Period	Secondary	Primary	Allocation Factor[1]			CF[2]
		-(dollars per kW)-			--(dollars per kW)--		
	Peak						
1.	Distribution	38.29[3]	36.00[3]	.60	25.44	23.92	.903
	Off Peak						
2.	Distribution	38.29[3]	36.00[3]	.40	16.21	15.24	.945

[1] Assumed 60/40 since actual data not available.

[2] Coincidence Factor (CF) is the average of monthly peak demands in period ÷ peak demand for period.

[3] Distribution marginal unit cost from schedule 5.4.3, page 2 has been adjusted by capacity adjustment factor to account for electric losses between components of the distribution system and the secondary voltage delivery level.

UTAH POWER AND LIGHT
CUSTOMER ACCOUNTS EXPENSE PER WEIGHTED CUSTOMER

		(1) 1974	(2) 1975	(3) 1976	(4) 1977	(5) 1978
1.	Customer Accounts Expense ($000)	4,097	6,053	7,632	8,435	*
2.	Customers[1]	327,502	341,122	357,122	374,807	-
3.	Customer Account Expense Per Customer	12.51	17.74	21.37	22.50	-
4.	Customer Accounts Expense Weighting Factor[2]	1.20	1.20	1.20	1.20	-
5.	Expense Per Weighted Customer (line 3 ÷ line 4)	10.43	14.78	17.81	18.75	-
6.	Inflation Factor[3] (1978 = 100)	.69	.79	.87	.920	1.000
7.	Expense Per Weighted Customer in 1978 Dollars (line 5 ÷ line 6)	15.11	18.71	20.47	20.38	-
8.	Estimated Expense of the Planning Period[4]					20.43

[1] Average number of customers.

[2] Based upon customer accounts expenses on an account-by-account basis and average number of customers, both by class of service from UP&L's cost-of-service study.

[3] 1977 based on Electric Labor Cost Index from the Handy-Whitman Index of Public Utility Construction Costs.

[4] Average of line 7 1976-1977.

*No data provided.

NOTE: Lines 1 and 2 from FPC Form 1.

UTAH POWER AND LIGHT
CUSTOMER ACCOUNTS BY CLASS OF SERVICE

	Class	(1) Customer Accounts Expense[1]	(2) Weighting Factor[2]	(3) Weighted Customer Accounts Expense (line 1 x line 2)
1.	Residential	20.43	1.0	20.43
2.	Commercial	20.43	2.0	40.86
3.	Industrial	20.43	5.0	102.15
4.	Street Lighting	20.43	0.5	10.22
5.	Irrigation	20.43	2.0	40.86

[1] From schedule 6.1.

[2] Estimated by CH2M HILL.

UTAH POWER AND LIGHT
SALES EXPENSE PER WEIGHTED CUSTOMER

		(1) 1974	(2) 1975	(3) 1976	(4) 1977	(5) 1978
1.	Sales Expense ($000)	1,026	960	1,464	1,941	*
2.	Customer[1]	327,502	341,122	357,122	374,807	-
3.	Sales Expense Per Customer	3.13	2.81	4.10	5.18	-
4.	Sales Expense Weighting Factor[2]	1.20	1.20	1.20	1.20	-
5.	Expense Per Weighted Customer	2.61	2.34	3.42	4.32	-
6.	Escalation Rate[3]	.69	.79	.87	0.92	1.00
7.	Expense Per Weighted Customer in 1978 (line 5 ÷ line 6)	3.78	2.96	3.93	4.70	-
8.	Estimated Expense for the Planning Period[4]			4.32		

[1] Average number of customers.

[2] Based upon sales expense and average number of customers, both by class of service from UP&L's cost-of-service study.

[3] 1977 based on Electric Labor Cost Index from the Handy-Whitman Index of Public Utility Construction.

[4] Average of line 7 1976-1977.

*No data provided.

NOTE: Lines 1 and 2 from FPC Form 1.

UTAH POWER AND LIGHT
SALES EXPENSE BY CLASS OF SERVICE

	Class	Customer Accounts Expense[1]	Weighting Factor[2]	Weighted Customer Accounts Expenses (Line 1 x Line 2)[5]
1.	Residential	$ 4.32	1.0	$ 4.32
2.	Commercial	4.32	2.0	8.64
3.	Industrial	4.32	5.0	21.60
4.	Street Lighting	4.32	0.5	2.16
5.	Irrigation	4.32	2.0	8.64

[1]From schedule 6.2 x column 1.

[2]Estimated by CH2M HILL.

UTAH POWER AND LIGHT
DERIVATION OF ANNUAL MARGINAL
STREET LIGHTING COSTS*

Type and Size of Lamp*

1. Long-Run Unit Investment
2. With General Plant Loading (line 1 x 1.052)[2]
3. Annual Economic Charge Related to Capital Investment[3]
4. Administrative and General Loading[4]
5. Total (line 3 + line 4)
6. Annualized Cost (line 2 x line 5)
7. Street Lighting O&M Expenses[5]
8. With Administrative and General Loading (line 7 x 1.26)
9. Energy Cost[7]
10. Demand-Related Cost[8]
11. Total Street Lighting Cost-Company-Owned (line 6 + line 8 + line 9 + line 10)

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[1]Incremental investment; includes lamp, fixture, and labor. Supplied by UP&L.

[2]Based on an analysis of the historic relationship between additions to general plant and additions to electric plant in service less general plant additions.

[3]Schedule 2.1.4.

[4]Schedule 3.0, line 32.

[5]Estimated 1978 Street Lighting Expense supplied by Utah Power and Light divided by the number of lamps.

[6]Schedule 4, line 3, column 30.

[7]Based on monthly usage and energy cost of __ cents per kWh (schedule 8.2, line 7, column 2).

[8]Generation transmission and distribution from schedules 5.1.4, 5.2.4, and 5.4.4.

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*NOTE: No data provided.

UTAH POWER AHD LIGHT
DERIVATION OF MARGINAL RUNNING COSTS
YEAR 1977

	Plant	(1) Net Peak On Demand (kW)	(2) Net Generation (MWh)	(3) Fuel Costs $	(4) Fuel Costs Mills/kWh	(5) Running Hours (Col. 2 ÷ Col. 1 x 100)
1.	Gadsby #1	66,000	262,935	5,248,654	20.0	398
2.	Little Mountain	16,000	60,841	1,285,410	16.9	3,803
3.	Hale #2	45,000	290,918	3,199,313	11.0	6,465
4.	Gadsby #3	102,000	659,415	6,158,255	9.4	6,465
5.	Gadsby #2	75,000	376,803	3,534,155	9.3	5,024
6.	Carbon #1	66,000	443,545	3,715,779	8.4	6,720
7.	Carbon #2	105,000	685,998	5,160,676	7.5	6,533
8.	Huntington #1	415,000	1,764,716	11,710,691	6.6	4,252
9.	Huntington #2	415,000	1,490,056	9,643,180	6.5	3,591
10.	Naughton #1	160,000	1,137,960	5,926,623	5.2	7,112
11.	Naughton #3	321,000	2,030,087	10,514,000	5.2	6,324
12.	Naughton #2	222,000	1,340,254	6,926,200	5.2	6,037
13.	Total	2,008,000				
14.	Peak Running Costs[1]		20.0			
15.	Off Peak Running Costs[2]		9.43			

[1] Column 4, line 1.

[2] Weighted average of column 4, lines 2-12.

NOTE: From column 5 it was determined that Gadsby is the peaking plant and the others are baseload plants.

SOURCE: FPC Form 12.

UTAH POWER AND LIGHT
MARGINAL ENERGY COSTS BY COSTING PERIOD

		(1)	(2)
		Costing Period	
		Peak Hours	Off-Peak Hours
		(mills/kWh)	
1.	Marginal Running Cost[1]	20.00	9.43
2.	Administrative and General Expense (Mills per kWh)[2]	.96	.96
3.	Cash Working Capital (Mills per kWh) (line 1 + line 2 x 1/8)	2.62	1.30
4.	Revenue Requirement for Cash Working Capital (Mills per kWh) (line 3 x 1.1701)[3]	3.07	1.52
5.	Marginal Energy Cost (Mills per kWh) (line 1 + line 2 + line 4)	24.03	11.91
6.	Marginal Energy Loss Factor For Secondary Service[4]	1.130	1.130
7.	Marginal Energy Cost Including Losses for Secondary Service (Mills per kWh) (line 5 x line 6)	27.15	13.46
8.	Marginal Energy Loss Factor for Primary Service[5]	1.104	1.104
9.	Marginal Energy Cost Including Losses for Primary Service (Mills per kWh) (line 5 x line 8)	26.53	13.15
10.	Marginal Energy Loss Factor for 46-69 kV Service[6]	1.076	1.076
11.	Marginal Energy Cost Including Losses for 46-69 kV Service (line 5 x line 10)	25.86	12.82
12.	Marginal Energy Loss Factor for 138 kV Service[7]	1.027	1.027
13.	Marginal Energy Cost Including Losses for 138 kV Service (line 5 x line 12)	24.68	12.23

[1] From table 8.1.

[2] Schedule 3.0, line 34.

[3] Marginal Cost of Capital. Includes overall return (future overall cost of capital in 1985), and Federal and state income tax as a percentage of working capital.

[4] Schedule 4.2, line 1, column 5.

[5] Schedule 4.2, line 2, column 5.

[6] Schedule 4.2, line 3, column 5.

[7] Schedule 4.2, line 4, column 5.

UTAH POWER AND LIGHT
SUMMARY OF MARGINAL COSTS BY COSTING PERIOD AND SERVICE VOLTAGE

		(1)	(2)	(3)	(4)
		Costing Period			
		Peak Season		Off-Peak Season	
		Peak Hours	Off-Peak Hours	Peak Hours	Off-Peak Hours
	Secondary				
1.	Seasonal Demand-Related Cost[1] ($/kW)	125.61	--	80.77	--
2.	Energy Cost[2] (mills/kWh)	27.15	13.46	13.46	13.46
	Primary				
3.	Seasonal Demand-Related Cost[1] ($/kW)	118.10	--	75.23	--
4.	Energy Cost[2] (mills/kWh)	26.53	13.15	13.15	13.15
	46-69 kV				
5.	Seasonal Demand-Related Cost[1] ($/kW)	117.50	--	73.58	--
6.	Energy Cost[2] (mills/kWh)	25.86	12.82	12.82	12.82
	138 kV				
7.	Seasonal Demand-Related Cost[1] ($/kW)	111.12	--	70.76	--
8.	Energy Cost[2] (mills/kWh)	24.68	12.23	12.23	12.23
	Street Lighting				
9.	Seasonal Demand-Related Cost[1] ($/kW)	*	*	*	*
10.	Energy Cost[2] (mills/kWh)	27.15	13.46	13.46	13.46

[1] Sum of costing period generation (Schedule 5.1.4), transmission (Schedule 5.2.4), and distribution (Schedule 5.4.5) costs per kW.

[2] Schedule 8.2.

* No data available.

SUMMARY OF MARGINAL CUSTOMER COSTS BY CUSTOMER CLASS

Customer Class	Annual Customer Costs
Residential	$131.00
Commercial	166.00
Industrial	289.00
Irrigation	152.00
Street Lighting	98.00

SOURCE: Schedule 5.3.3.

Chapter 3
COST-BENEFIT ANALYSIS

Time-of-use metering is cost-effective only when the cost of metering is offset by savings in energy anc capacity. In this chapter we have compared the costs and benefits of seasonal and time-of-day pricing for the residential and small commercial classes, which are not currently demand-metered. Customers who are currently metered would not incur any additional costs for metering; therefore, any reduction in on-peak capacity or energy represents a savings and a positive net benefit.

In this study, the benefits of time-of-day pricing and savings in capacity and energy costs are measured in terms of the marginal cost of capacity and the marginal running cost premium (the difference between running costs on and off peak). The values of these savings are developed in Schedules 10 through 13. The cost of time-of-use pricing is the incremental cost of installing, reading, and maintaining metering equipment, as shown in Schedule 14. In order to determine potential kWh and kW savings, it was necessary to make some assumptions about customer response to time-of-use pricing. Since actual data on residential and commercial demand elasticities for the Utah Power and Light system are not available, we have elected to use a range of elasticities and peak period price increases. On the basis of two studies on residential customer response conducted by Arizona Public Service Commission and Connecticut Light and Power, a range of -0.6 to -1.3 was chosen to represent the long-run elasticity of residential customers. Due to the lack of data on commercial customer reponse, commerical demand elasticity was assumed to be the same as residential demand elasticity. The range of assumed elasticities, combined with assumed peak period rate increases of 10 percent and 50 percent, results in a wide range of derived kWh reductions.

Schedules 15 through 18 calculate benefit-cost ratios of time-of-day metering by customer consumption size for residential and commercial customers. For each consumption group a peak period kWh reduction due to an assumed percentage rate increase was calculated. Given the number of peak hours in a month and a load factor, the kW reduction during the peak period was derived. The dollar savings per kW was applied to the peak period kW reduction to obtain the annual dollar saving due to peak demand reduction. The annual saving divided by the annual cost of metering results in a benefit-cost ratio for each consumption group. The breakeven consumption, the consumption at which the annual saving due to peak demand reduction is equal to the annual cost of the meter, was also calculated.

Schedules 15 and 17 compute cost-benefit ratios for residential and commercial customers, assuming a 10-percent peak period rate increase and derived kWh reductions of 6 percent and 13 percent. From the results of these schedules, it can be concluded that it would be cost-effective to meter residential customers consuming over 1,400 kWh/month assuming a -0.6 elasticity, or 650 kWh/month assuming a -1.3 elasticity. Under the same assumptions commercial consumption would have to be over 1,650 and 760 kWh/month, respectively.

Schedules 16 and 18 compute cost-benefit ratios for residential and commercial customers assuming a 50-percent peak period rate increase, and derived kWh reductions of 30 percent and 65 percent. Under these assumptions, residential customers consuming over 250 kWh/month, assuming a -0.6 elasticity, and customers consuming over 120 kWh/month, assuming a -1.3 elasticity, could be metered cost-effectively. Commercial customers would have to consume 333 and 154 kWh/month, respectively, to be metered cost-effectively under these same assumptions.

Daily load charts show that 90 percent of total residential kWh consumption and 87 percent of total commercial kWh consumption take place during the peak period. From this estimate it was determined that average peak period consumption per month in 1977 was 594 kWh for residential customers and 4,400 kWh for commercial customers. The average residential customer, with a -1.3 elasticity, would warrant metering under the 10-percent peak period rate increase assumption. Under the 50-percent peak period rate increase assumption, the average residential customer would warrant metering at both elasticities. The average commercial customer would warrant metering under all assumptions.

UTAH POWER AND LIGHT
INCREMENTAL CAPACITY INVESTMENT
1978 $/kW

		(1) Incremental Capacity Investment	(2) Annual Charge (%)	(3) Annualized Incremental Investment Cost (1) x (2)
1.	Generation - Installed	$210.00	12.08	25.37
2.	Transmission	484.80	11.75	56.96
3.	Distribution	187.47	11.96	22.43
4.	Subtotal	882.27		104.76
5.	Reserves for Outages[1]	--	--	--
6.	Incremental Capacity Investment	$882.27		104.76

[1] Included in line 1 (18%).

SOURCES: Incremental Capacity Investment:
Generation, Schedule 5.1.3
Transmission, Schedule 5.2.1
Distribution, Schedule 5.4.1
Annual Charge:
Generation, Schedule 2.2.1
Transmission, Schedule 2.2.2
Distribution, Schedule 2.2.3

UTAH POWER AND LIGHT
HOURS DURING PEAK PERIOD

1.	Peak Hours/Day	18
2.	Peak Days/Week	5
3.	Peak Months/Year	5
4.	Total Peak Hours	1,980

NOTE: Daily Peak: 5 a.m. - 11 p.m., Monday-Friday
Off peak: 11 p.m. - 5 a.m., Monday-Friday
Seasonal Peak: May-September
Off peak: October-April

UTAH POWER AND LIGHT
ANNUAL SAVINGS IN RUNNING COSTS/kW

Marginal Running Costs

1.	Peak Period ¢/kWh	2.000[1]
2.	Off Peak Period (¢/kWh)	.943[1]
3.	Marginal Running Costs Premium (¢/kWh) (1) - (2)	1.057
4.	Total Peak Hours	1,980[2]
5.	Residential Coincidental LF	.75[3]
6.	Peak Hours-Residential (4) x (5)	1,485
7.	Annual Residential Savings in Running Costs ($/kW) (3) x (6) ÷ 100	15.70
8.	Commercial Coincidental LF	.87[3]
9.	Peak Hours-Commercial (4) x (8)	1,723
10.	Annual Commercial Savings in Running Costs ($/kW) (3) x (9) ÷ 100	18.21

[1] Schedule 8.1.

[2] Schedule 11, line 4.

[3] Estimated by analysis of sample daily loads for class.

UTAH POWER AND LIGHT
ANNUALIZED BENEFITS OF TIME-OF-DAY PRICING
1978 DOLLARS/kW

		(1) Generation	(2) Transmission	(3) Distribution	(4) Total
1.	Incremental Capacity Investment ($/kW)[1]	210.00[2]	484.80	187.47	
2.	Annual Charge (%)	12.08	11.75	11.96	
3.	Annualized Incremental Capacity Investment ($/kW) (1)x(2)	25.37	56.96	22.43	104.76
4.	Annual Savings in Running Costs ($/kW)[3]				
5.	Residential				15.70
6.	Commercial				18.21
7.	Total Annual Benefits ($/kW)				
8.	Residential (3)+(5)				120.46
9.	Commercial (3)+(6)				122.97

[1] Schedule 10.

[2] Includes Reserves for Outages.

[3] Schedule 12, lines 7 and 10.

UTAH POWER AND LIGHT
ANNUALIZED COSTS FOR TIME-OF-DAY METERING

		(1978 $/Meter)
	Investment Costs	
1.	Purchase[1]	130.00
2.	Installation[2]	20.00
3.	Total Initial Investment	150.00
	Incremental Annual Costs[3]	
4.	Maintenance	10.00
5.	Reading and Processing	3.00
6.	Total Annual Costs	13.00
7.	Annualized Investment Costs[4]	17.95
8.	Annualized Total Incremental Cost (line 6 + line 7)	30.95

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[1] Based on manufacturer's estimates of a two-dial kWh meter.

[2] Assumes $20 installation costs.

[3] Based on a west coast utility's estimates for time-of-day metering equipment.

[4] Annual carrying charge for distribution plant (Schedule 10) 11.96% x line 3.

UTAH POWER AND LIGHT
COMPUTATION OF BENEFIT/COST RATIO OF
TIME-OF-DAY METERING BY RESIDENTIAL
CUSTOMER CONSUMPTION SIZE
(ASSOCIATED WITH A 10% PEAK PERIOD RATE INCREASE)

Schedule 15

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Residential Consumption Size (kWh/month)	Peak Period kWh Reduction/mo[2]		Peak Period kW Reduction[3]		Savings/ kW[4]	Benefit/Savings From kWh Reduction[5]		Annual Cost of Meter[6]	Benefit/Cost Ratio[7]	
	6%[1]	13%[1]	6%[1]	13%[1]		6%[1]	13%[1]		6%[1]	13%[1]
0-250	6.75	14.62	.02	.05	120.46	2.41	6.02	30.95	.08	.19
251-500	20.25	43.88	.07	.15	120.46	8.43	18.07	30.95	.27	.58
501-800*	35.10	76.05	.12	.26	120.46	14.46	31.32	30.95	.47	1.01
801-1000	48.60	105.30	.16	.35	120.46	19.27	42.16	30.95	.62	1.36
1001-2000	81.00	175.50	.27	.59	120.46	32.52	71.07	30.95	1.05	2.30
Breakeven consumption[8] 1407 (6% reduction) 650 (13% reduction)	76.00	76.00	.26	.26	120.46	30.95[9]	30.95[9]	30.95	1.00	1.00

[1] Assuming a 10% peak period rate increase and demand elasticities of -0.6 and -1.3, the derived reductions in kWh consumption are 6% and 13%, respectively. These long-run elasticities are the results of studies by the Arizona Public Service Commission and Connecticut L&P.

[2] Midpoint of range x % reduction x % of total residential consumption occurring in peak period (estimated at 90%).

[3] Peak period kWh reduction (columns 1 and 2) ÷ number of peak hours in a month (396) ÷ residential load factor (.75).

[4] Schedule 13, line 8.

[5] Columns 4 and 5 x column 6.

[6] Schedule 14, line 7.

[7] Column 9 ÷ columns 7 and 8.

[8] Assuming a 1.0 cost/benefit ratio.

[9] May not total due to rounding.

* Average residential consumption/month in 1978 $\cong$ 594 kWh.

Schedule 16

UTAH POWER AND LIGHT
COMPUTATION OF BENEFIT/COST RATIO OF
TIME-OF-DAY METERING BY RESIDENTIAL
CUSTOMER CONSUMPTION SIZE
(ASSOCIATED WITH A 50% PEAK PERIOD RATE INCREASE)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Residential Consumption Size (kWh/month)	Peak Period kWh Reduction/mo[2]		Peak Period kW Reduction[3]		Savings/ kW[4]	Benefit/Savings From kWh Reduction[5]		Annual Cost of Meter[6]	Benefit/Cost Ratio[7]	
	30%[1]	65%[1]	30%[1]	65%[1]		30%	65%		30%	65%
0-250	33.75	73.13	.11	.25	120.46	13.25	30.12	30.95	.43	.97
251-500	101.25	219.38	.34	.74	120.46	40.96	89.14	30.95	1.32	2.88
501-800*	175.50	380.25	.59	1.28	120.46	71.07	154.19	30.95		
801-1,000	243.00	526.50	.82	1.77	120.46	98.78	213.21	30.95	3.19	6.89
1,001-2,000	405.00	877.50	1.36	2.95	120.46	163.83	355.36	30.95	5.29	11.48
Breakeven consumption[8] 281 (30% reduction) 130 (65% reduction)	76.0	.76	.26	.26	120.46	30.95[9]	30.95[9]	30.95	1.00	1.00

[1] Assuming a 50% peak period rate increase and demand elasticities of -0.6 and -1.3, the associated reduction in kWh consumptions is 30% and 65%, respectively. These long-run elasticities are the results of studies by the Arizona Public Service Commission and Connecticut L&P.

[2] Midpoint of range x % reduction x % of total residential consumption occurring in peak period (estimated at 90%)..

[3] Peak period kWh reduction (column 1 + column 2) ÷ number of peak hours in a month (396) ÷ residential load factor (.75).

[4] Schedule 13, line 8.

[5] Column 4 + column 5 x column 6.

[6] Schedule 14, line 7.

[7] Column 9 ÷ column 7 + column 8.

[8] Assuming a 1.0 cost/benefit ratio.

[9] May not total due to rounding.

* Average residential consumption/mo in 1977 $\cong$ 594 kWh.

UTAH POWER AND LIGHT
COMPUTATION OF BENEFIT/COST RATIO OF
TIME-OF-DAY METERING BY COMMERCIAL
CUSTOMER CONSUMPTION SIZE
(ASSOCIATED WITH A 10% PEAK PERIOD RATE INCREASE)

Schedule 17

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Commercial Residential Consumption Size (kWh/month)	Peak Period kWh Reduction/mo[2]		Peak Period kW Reduction[3]		Savings/ kW[4]	Benefit/Savings From kWh Reduction[5]		Annual Cost of Meter[6]	Benefit/Cost Ratio[7]	
	6%[1]	13%[1]	6%[1]	13%[1]		6%	13%		6%	13%
0-250	6.53	14.14	.02	.04	122.97	2.46	4.92	30.95	.08	.16
251-500	19.58	42.41	.06	.12	122.97	7.38	14.76	30.95	.24	.48
501-800	33.93	73.52	.10	.21	122.97	12.30	25.82	30.95	.40	.83
801-1000	46.98	101.79	.14	.30	122.97	17.22	36.89	30.95	.56	1.19
1001-2000	78.30	169.65	.23	.49	122.97	28.28	60.26	30.95	.91	1.95
2001-4000	156.60	339.30	.45	.98	122.97	55.34	120.51	30.95	1.79	3.89
4001-6000*	261.00	565.50	.76	1.65	122.97	93.46	202.90	30.95	3.02	6.56
6001-8000	365.40	791.70	1.06	2.30	122.97	130.35	282.83	30.95	4.21	9.14
8001-10000	469.80	1,017.90	1.36	2.95	122.97	167.24	362.76	30.95	5.40	11.72
10001-15000	652.50	1,413.75	1.89	4.10	122.97	232.41	504.18	30.95	7.51	16.29
Breakeven consumption 1650 (6% reduction) 762 (13% reduction)	86.13	86.13	.25	.25	122.97	30.95[9]	30.95[9]	30.95	1.00	1.00

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[1] Assuming a 10% peak period rate increase and demand elasticities of -0.6 and -1.3 the derived reduction in kWh consumption is 6% and 13%, respectively. These long-term elasticities are the results of studies by the Arizona Public Service Commission and Connecticut L&P.

[2] Midpoint of range x % reduction x % of total commercial consumption occurring in peak period (estimated at 87%).

[3] Peak period kWh reduction (columns 1 and 2) ÷ number of peak hours in a month (396) ÷ commercial load factor (.87).

[4] Schedule 13, line 9.

[5] Columns 4 and 5 x column 6.

[6] Schedule 14, line 7.

[7] Column 9 ÷ columns 7 and 8.

[8] Assuming a 1.0 cost/benefit ratio.

[9] May not total due to rounding.

* Average commercial consumption/month in 1977 ≅ 594.

Schedule 18

UTAH POWER AND LIGHT
COMPUTATION OF BENEFIT/COST RATIO OF
TIME-OF-DAY METERING BY COMMERCIAL
CUSTOMER CONSUMPTION SIZE
(ASSOCIATED WITH A 50% PEAK PERIOD RATE INCREASE)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Commerical Consumption Size (kWh/month)	Peak Period kWh Reduction/mo[2] 30%[1]	65%[1]	Peak Period kW Reduction[3] 30%[1]	65%[1]	Savings/ kW[4]	Benefit/Savings From kWh Reduction[5] 30%[1]	65%[1]	Annual Cost of Meter[6]	Benefit/Cost Ratio[7] 30%	65%
0-250	32.63	70.69	.09	.21	122.97	11.07	25.82	30.95	.36	.83
251-500	97.88	212.06	.28	.62	122.97	34.43	76.24	30.95	1.11	2.46
501-800	169.65	367.58	.49	1.07	122.97	60.26	131.58	30.95	1.95	4.25
801-1,000	234.90	508.95	.68	1.48	122.97	83.62	182.00	30.95	2.70	5.88
1,001-2,000	391.50	848.25	1.14	2.46	122.97	140.19	302.51	30.95	4.53	9.77
2,001-4,000	783.00	1,696.50	2.27	4.92	122.97	279.14	605.01	30.95	9.02	19.55
4,001-6,000*	1,305.00	2,827.50	3.79	8.21	122.97	466.06	1,009.58	30.95	15.06	32.62
6,001-8,000	1,827.00	3,958.50	5.30	11.49	122.97	651.74	1,412.93	30.95	21.06	45.65
8,001-10,000	2,349.00	5,089.50	6.82	14.77	122.97	838.66	1,816.27	30.95	27.10	58.68
10,001-15,000	3,262.50	7,068.75	9.47	20.52	122.97	1,164.53	2,523.34	30.95	37.63	81.53
Breakeven Consumption 332.6 (30% reduction) 153.5 (60% reduction)	86.81	86.80	.25	.25	122.97	30.95[9]	30.95[9]	30.95	1.00	1.00

[1] Assuming a 50% peak period rate increase and demand elasticities of -0.6 and -1.3, the derived reduction in kWh consumption is 30% and 65%, respectively. These long-term elasticities are the results of studies by the Arizona Public Service Commission and Connecticut L&P.

[2] Midpoint of range x % reduction x % of total commercial consumption occurring in peak period (estimated at 87%).

[3] Peak period kWh reduction (column 1 + column 2) ÷ number of peak hours in a month (396) ÷ commercial load factors (.87).

[4] Schedule 13, line 9.

[5] Column 4 + column 5 x column 6.

[6] Schedule 14, line 7.

[7] Column 9 ÷ column 7 + column 8.

[8] Assuming a 1.0 cost/benefit ratio.

[9] May not total due to rounding.

* Average commercial consumption/mo in 1977 ≅ 594.

Chapter 4
DEVELOPING TIME-OF-USE RATES

Selection of Peakload Periods

In the absence of an hourly LOLP study, an examination of monthly and daily peakloads of Utah Power and Light Company was conducted to determine peakload periods.

From an analysis of the monthly system peak for calendar year 1977, the contiguous months of May through September, inclusive, were selected as peak period.

From an examination of typical daily peak loads from throughout the year, a pattern emerged indicating a sharp buildup of load between 6 a.m. and 7 a.m., and a dropoff of load between 11 p.m. and midnight. The daily peak and off-peak hours were thus selected. The hour from 5 a.m. to 6 a.m. was also included in the daily peak period because of the potential for that hour to become shoulder peak.

Peak and Off-Peak Capacity and Energy Charges

Schedule 9.0 presents the marginal cost of capacity and energy for seasonal and daily peak and off-peak periods by delivery voltage. (The difference in costs by voltage level is the result of the adjustment for losses at each delivery level.)

There are two further refinements that must be made to create the monthly capacity cost factor. First, the marginal capacity costs must be divided by the number of months in the peak period (5) to obtain monthly values. Second, for those customer classes in which only energy (kWh) will be metered, the capacity charge must be converted to an energy charge by estimating average class load factors.

Customer Charges

Marginal customer costs are developed by Schedule 5.3.3 and are summarized on Schedule 9.1. These are annual costs and therefore must be divided by 12 to obtain monthly charges for ratemaking purposes.

Development of Estimated Revenues Using Marginal Costs

Having established customer, capacity, and energy costs by periods and voltage levels, rate schedules using these costs can readily be constructed. The next step is the development of estimated revenues by the application of the proposed rate schedules to the estimated demands, energy consumption, and number of customers. If historical data are being used for this analysis, some consideration must be made for load shifting and usage reduction due to marginal rate levels.

The estimated revenue will undoubtedly be substantially greater than the allowable revenue requirements of the utility. If the Commission is to avoid allowing the utility windfall profits, the rate levels must be scaled back to match the revenue requirements. There are several methods that can be used to accomplish this task.

The first method is to simply determine the relation of the total revenue requirements of the utility to the estimated total revenues from the proposed rate levels. This percentage can then be applied to each charge in each rate schedule to bring estimated revenues in line with desired revenue requirements.

Another method, which applies the rule of inverse elasticity, reduces or eliminates the least elastic rate charge (i.e., customer charge) or rate class (i.e., residential) by the amount necessary to equate revenues with revenue requirements.

As was mentioned before, estimates of the effect of load shift and usage reduction must be made in order to ensure that revenues are not reduced below the revenue requirement level.

Chapter 5
RECOMMENDATIONS TO THE IDAHO COMMISSION

As indicated earlier in the report, this illustrative study was based on assumptions and on data from other utilities as well as on data from Utah Power and Light Company (UP&L). Data from other utilities would only be reliable when rate levels and load characteristics are nearly similar. Before a definitive marginal cost time-of-use study for UP&L can be made, it would be desirable to replace other utility data and assumptions with actual UP&L data. We feel the Commission should ask the company to make the study and, concurrently, furnish all data necessary to the study to the Commission for its use.

Because the customer reaction to the new rate forms is extremely critical, it would seem prudent to develop and establish some experimental rates from which actual customer response information can be evaluated. Such rates and the conditions under which they are formulated and tested must be carefully designed to ensure reliable results. The test rates should be applied to a carefully selected sample of customers under controlled conditions whereby, while there is no financial penalty to customers for not shifting this peak use or reducing consumption, there will be rewards of lower bills if customers respond to the test price signals.

A carefully selected control sample must also be monitored at the same time under the existing rates. The ideal test period would be 24 months, so that the result can be adjusted for variances in weather and other abnormal conditions.

It must be kept in mind that responses by customers of other utilities, under circumstances unique only to those utilities, may or may not be applicable to UP&L customers. Therefore, we recommend that marginal rates not be required until actual data or data of proven comparability reflecting customer response are available for the system to which new rates are to be applied.